UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit AA: CoPUC, Decision No. R24-0602, issued on August 22, 2024,
in Proceeding No. 23A-0585E

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Decision No. R24-0602

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 23A-0585E

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IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

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# RECOMMENDED DECISION GRANTING UNOPPOSED JOINT MOTION TO APPROVE COMPREHENSIVE SETTLEMENT AGREEMENT, APPROVING COMPREHENSIVE SETTLEMENT AGREEMENT, AND GRANTING ELECTRIC RESOURCE PLAN APPLICATION AS AMENDED BY COMPREHENSIVE SETTLEMENT AGREEMENT

Issued Date: August 22, 2024

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Colorado PUC E-Filings System

## I. STATEMENT

### A. Procedural Background[1]

1. On December 1, 2023, Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed its 2023 Electric Resource Plan ("ERP") Application ("Application"), including the Direct Testimony of eight witnesses and attachments to the same. The filing of the ERP Application commenced this Proceeding.

2. By Decisions No. R24-0080-I and R24-0085-I[2], issued February 6 and February 8, 2024, respectively, the undersigned Administrative Law Judge ("ALJ"), among other things: acknowledged the interventions of the trial staff of the Colorado Public Utilities Commission ("Staff"), Office of Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), and Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrlec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., Garland Light & Power Co., (collectively, the "Wyoming Cooperatives"), Poudre Valley Rural Electric Association, Inc. ("PVREA"), Highline Electric Association ("Highline"), K.C. Electric Association ("K.C."), San Isabel Electric Association, Inc. ("SIEA"), Southeast Colorado Power Association ("SECPA"), and Y-W Electric Association, Inc. ("Y-W"); granted the interventions of the Natural Resources Defense Council and the Sierra Club (together, the "Conservation Coalition"), White River Electric Association ("WREA"), Western Resource

[1] The entire procedural history of this proceeding is provided in previous decisions and is partially repeated here, to the extent necessary to provide procedural context for the above-titled decision.

[2] Decision No. R24-0085-I provided certain clarifications for Decision No. R24-0080-I.

Advocates ("WRA"), Office of Just Transition ("OJT"), the Colorado Independent Energy Association ("CIEA"), Colorado Department of Public Health and Environment ("CDPHE"), Interwest Energy Alliance ("Interwest"), La Plata Electric Association, Inc. ("LPEA") and Mountain Parks Electric, Inc. ("MPE") (together, "LPEA/MPE"), the Colorado Solar and Storage Association ("COSSA") and the Solar Energy Industries Association ("SEIA") (together, "COSSA/SEIA"), and Moffat County ("Moffat") and the City of Craig ("Craig"), Colorado (together, "Moffat/Craig"); and a procedural scheduled to govern this Proceeding.

3. By Decision No. R24-0138-I, issued March 5, 2024, the undersigned ALJ adopted a revised procedural schedule to govern this Proceeding. Among other deadlines, the decision set a June 26, 2024 deadline for Stipulations/Settlement Agreements; a July 1, 2024 deadline for Witness Lists, Cross-Examination Estimates, and Final Exhibits List; a July 11, 2024 deadline for Settlement Testimony; a July 16-19, 2024 Evidentiary Hearing; and an August 1, 2024 deadline for Statements of Position.

4. On April 22, 2024, Tri-State filed Supplemental Direct Testimony, providing additional information in support of the Application.

5. On May 15, 2024, the Colorado Air Pollution Control Division ("APCD") filed its Verification Report ("Emissions Report"), verifying Tri-State's calculation of a forecasted emissions reduction of 89 percent by 2030 from Colorado sales for the submitted preferred portfolio.

6. By Decision No. R24-04060-I, the ALJ again modified the procedural schedule, extending the filing deadline for any settlement agreements through June 28, 2024.

7. On June 27, 2024, Tri-State, Highline, PVREA, Y-W, Interwest, Staff, UCA, CEO, Moffat/Craig, OJT, CIEA, COSSA/SEIA, Conservation Coalition, and WRA (the "Settling

Parties") filed their Unopposed Comprehensive Settlement Agreement ("Settlement Agreement"). With the Unopposed Comprehensive Settlement Agreement, the Settling Parties also filed their Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time ("Motion"). In the Motion, the Settling Parties indicate that the Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.[3]

8. By Decision No. R24-0496-I, issued July 10, 2024, the undersigned ALJ waived response time for the Motion, vacated the evidentiary hearing and the deadline for the filing of Statements of Position, and indicated that any additional relief sought in the Motion will be ruled upon by separate decision.

9. On July 7 and 9, 2024, the undersigned ALJ held Public Comment Hearings in this matter.

10. On July 10, 2024, Hearing Exhibit 203, the Settlement Testimony of Rebecca V. Lim (Staff's Settlement Testimony) was filed by Staff.

11. On July 11, 2024, Hearing Exhibit 122, the Settlement Testimony and Attachments of Susan K. Hunter on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 122" or "Ms. Hunter's Settlement Testimony") Hearing Exhibit 123, the Settlement Testimony and Attachments of Lisa K. Tiffin on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 123" or "Ms. Tiffin's Settlement Testimony"), Hearing Exhibit 124, the Settlement Testimony and Attachments of Brian L. Thompson on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 124" or "Mr. Thompson's Settlement Testimony"), and Hearing Exhibit 125, the Settlement Testimony and

[3] Motion at 2.

Attachments of Chad Orvis on Behalf of Tri-State Generation and Transmission Association, Inc. (collectively, "Tri-State's Settlement Testimony") were filed by Tri-State.

12. On July 12, 2024, Hearing Exhibit 903 Testimony of Clare Valentine in Support of Settlement on Behalf of Western Resource Advocates ("Hearing Exhibit 903" or "WRA's Settlement Testimony") was filed by WRA.

13. On July 11, 2024, Hearing Exhibit No. 1603 Settlement Testimony of Commissioner Melody Villard on Behalf of the Coal Transition Communities, Moffat County and the City of Craig, Colorado ("Hearing Exhibit 1603" or "Moffat/Craig's Settlement Testimony") was filed by Moffat/Craig.

14. On July 11, 2024, Hearing Exhibit 1501 Settlement Testimony of Mike Kruger on Behalf of Colorado Solar and Storage Association and Solar Energy Industries Association ("Hearing Exhibit 1501" or "COSSA/SEIA's Settlement Testimony) was filed by COSSA/SEIA.

15. On July 12, 2024, the Answer Testimony of Wade Buchanan on Behalf of the Colorado Office of Just Transition Hearing Exhibit 1000[4] was filed by OJT.

### B. Background for This Proceeding

16. Tri-State is a generation and transmission cooperative that provides electric transmission service and is a wholesale seller of electric energy to 42 Utility Members in its service territory of four states using facilities located in five states.[5] Tri-State owns, operates, or has a major equipment ownership interest in more than 5,665 miles of high-voltage transmission lines and approximately 409 substations and switchyards.[6] Tri-State's interstate transmission facilities

[4] Although the title of this filing included the words "Answer Testimony," its timing and content make it clear it was intended as to be filed as OJT's Settlement Testimony and is therefore considered herein as such.

[5] Hearing Exhibit 107 at 6:9-11 (Direct Testimony and Attachments of Ryan J. Hubbard on Behalf of Tri-State Generation and Transmission Association, Inc.).

[6] *Id*. at 6:11-14.

are interconnected to other utilities, including Western Area Power Administration, Nebraska Public Power District, Black Hills Colorado Electric, Inc., PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, Colorado Springs Utilities, Basin Electric Power Cooperative, Tucson Electric Power, Public Service Company of New Mexico, and Deseret Generation & Transmission Cooperative.[7]

17. This Proceeding concerns Tri-State's second ERP application submitted pursuant to Rule 3605.[8] The Application, with its supporting testimony and attachments, are intended to describe how Tri-State will ensure reliability and resource adequacy, maintain affordability for its members, and meet compliance obligations, including environmental responsibility obligations.[9]

18. A significant component underlying the Application is that on September 13, 2023, Tri-State submitted a Letter of Interest to the United States Department of Agriculture ("USDA"), seeking significant funding through the Empowering Rural America ("New ERA") program of the Rural Utilities Service. The New ERA program, which was established through the Inflation Reduction Act ("IRA"), includes $9.7 billion in federal funding for financial assistance to support the purchase of renewable energy, zero-emission, and carbon capture systems.[10] In its Application, Tri-State put forward as its preferred portfolio an IRA Scenario that included several actions based on its application to the New ERA program. These actions included the acquisition of 255 MW owned renewable energy projects, 1,380 Megawatt ("MW") renewable and hybrid power purchase agreement projects, and 210 MW battery storage projects; and the retirements of Craig Unit 3 as of January 1, 2028, and Springerville Unit 3 no later than September 15, 2031.

[7] *Id*. at 6:15-21.
[8] Application at 1. *See also*, Proceeding No. 20A-0528E, which concerned Tri-State's first ERP Application with the Commission.
[9] *Id*. at 2.
[10] Attachment 1 to the Application (Stipulation between Tri-State, CEO, COSSA, UCA, County Electric Cooperative, Inc., Mountain View Electric Association, Inc., Sierra Club, and WRA), at 2-3.

19. With its Application, Tri-State submitted a stipulation with certain external stakeholders who agreed to support its acquisition in Phase II of resources pursuant to Tri-State's application to USDA, if its request for federal funding is approved in full.[11] Subsequently, in Supplemental Direct Testimony, Tri-State announced that it had received a notice to proceed from the USDA, and would thus be submitting a full application for New ERA funding.[12] At the time of this Decision, no announcements have been made by USDA regarding New ERA program awards.

### C. Settlement Agreement[13]

#### 1. General Terms, Contents of the Phase II Implementation Report, and Injection Study

20. The Settlement Agreement, which is attached to this Recommended Decision as Appendix A, sets forth the Settling Parties' agreement resolving all disputed issues in this Proceeding.[14]

21. The Settling Parties have agreed that the Commission should grant Tri-State's Application for approval of its 2023 ERP, subject to the terms of the Settlement Agreement. The Settling Parties agree that the compromise reached between the Settling Parties constitutes a just and reasonable resolution of all issues as part of Phase I of the ERP.[15]

22. In addition to certain specific terms which are discussed below, the Settling Parties also have agreed to numerous General Terms and Conditions, found in Section 6 of the Settlement Agreement.[16]

[11] *Id*. at 8.
[12] Hr. Ex. 101, Tiffin Supplemental Direct, p. 6.
[13] The following is intended as a summary of some of the main terms of the Settlement Agreement, rather than a full recitation of the same.
[14] Settlement Agreement, ¶1.3.
[15] *Id*.
[16] *See id*., at 31-34.

23. The Settling Parties have agreed upon certain contents of the Phase II Implementation Report, which is to be submitted 165 days after Phase II RFPs have been released.[17] The Implementation Report will include the items listed in Hearing Exhibit 101, Attachment LKT-3; annual emissions in short tons; a map of all Phase II bids, with an overlay identifying Disproportionately Impacted ("DI") Communities; highly confidential technical specifications for any gas resource bids advanced to Phase II modeling; identification of any bids located in Moffat County or the West End of Montrose County; and, for any bids located in the same areas, an estimate of the annual property tax expected to be paid to the county for bids selected and an explanation of why a given bid is not advanced to Phase II modeling, if applicable.[18]

24. Following Phase II, Tri-State agrees to conduct an injection study reflecting the anticipated Colorado transmission system in 2031, as further set forth in ¶4.11 of the Settlement Agreement.[19]

### 2. Requests for Proposals

25. The Settling Parties have agreed that the Commission should approve a Dispatchable Request for Proposals ("RFP"), a Standalone Storage RFP, and a Renewable RFP for issuance in Phase II.[20] While resources that are included within Tri-State's New ERA application will retain certain requirements related to geographic location, size, and technology type, Tri-State will remove those restrictions for RFPs seeking resources that are not included within the New ERA application.[21]

[17] Hr. Ex. 101, Attachment LKT-2, Rev. 1.
[18] Settlement Agreement, ¶4.10.
[19] *Id*., ¶4.11.
[20] *Id*., ¶4.2.
[21] *Id*. at ¶¶4.2.1., 4.2.3., 4.2.4., 4.2.5.

26. Furthermore, within one week of receiving a notice of award from USDA regarding New ERA funding, Tri-State commits to request a meeting with USDA to discuss flexibility related to funded projects. Tri-State will then file an informational notice with the Commission.[22] If New ERA guidance is provided at least 10 days before the issuance of the RFPs, Tri-State will modify its RFPs to match that guidance and informationally refile them with the Commission.[23]

27. The Settling Parties have agreed that Tri-State will modify Phase II Bid Security and refundability requirements, as further set forth in ¶4.2 of the Settlement Agreement. Among such modifications is the requirement for selected bidders to submit $10,000 per nameplate capacity megawatt ("MW") on a given project, due within 21 days of Tri-State filing its Phase II ERP Implementation Report.[24]

28. The Dispatchable RFP process will be modified so that the geographic location for gas plant bids (except tolling agreements) will be limited to Moffat County, no limits will be imposed on technology type or MW size, and Dispatchable RFPs must meet the carbon dioxide emission rate and performance requirements identified in the greenhouse gas emissions rules promulgated by the Environmental Protection Agency, as further set forth in ¶ 4.2.6 of the Settlement Agreement.

29. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an Extreme Weather Event ("EWE") sensitivity ("EWE Sensitivity"), including the requirement on Tri-State to model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters, and otherwise comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement.

[22] *Id*. at ¶ 4.2.7.
[23] *Id*. at ¶¶4.2.8., 4.2.8., 4.2.10.
[24] *Id*., ¶4.2.2.1.

30. Bids with commercial operational dates in 2026 and 2027 also will be required to have an established generator interconnection queue position.[25] Bids beyond those dates without an interconnection queue position will be entered into the Tri-State interconnection queue.[26]

31. The Settling Parties agree that Tri-State will update certain non-price factor bid evaluation criteria for its RFPs. Tri-State will make the relevant non-price factor information available to bidders as well as assumptions for use of surplus interconnection service at Tri- State-owned facilities. Among other changes, Tri-State will amend the "Development and Siting Status" narrative topics requested from bidders to address Community Stewardship, Tribal Consultation, and Land Use considerations—and specifically to seek information on community engagement and wildlife surveys--as further set forth in ¶4.7 of the Settlement Agreement.

### 3. Phase II Portfolios and Modeling and 2027 ERP

32. The Settling Parties have further agreed upon eight portfolios to be modeled in Phase II, with the potential for two additional portfolios to be modeled. These include Tri-State's preferred plan; a version of the preferred plan that allows other gas plant technology types (in addition to natural gas carbon capture and storage); a version of the preferred plan in which the model will not be required to select a gas resource, and constraints would be removed for non-New-ERA resources; a version of the preferred plan that limits gas resources to tolling agreements; an unconstrainted portfolio that allows the model to choose resources; a "no new gas" portfolio, contingent on whether all other portfolios select new gas resources; an optional portfolio of Tri-State's choosing; and back-up bid portfolios, as further set forth in ¶4.3 of the Settlement Agreement.

[25] *Id*., ¶4.5.
[26] *Id*.

33. Tri-State agreed to update modeling assumptions for non-tolling agreement gas plant bids to have a useful life of no later than 2050.[27]

34. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an EWE Sensitivity and comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement. Tri-State will also remodel any portfolios that fail to meet the Level II reliability criteria related to EWE Sensitivity.[28]

35. Tri-State also agreed to aim to control at least 5.5% of Tri-State's Colorado peak load through demand response programs by 2030.[29] Tri-State also agreed to model in-house demand response offerings to that effect.[30]

36. Tri-State will further subject each portfolio to at least 24 hours of run time in its modeling software, EnCompass.[31]

37. Tri-State will use the Phase II bids that pass bid evaluation as inputs to inform its 2027 ERP generic resource assumptions used in Phase I modeling of that ERP, as further set forth in ¶4.12 of the Settlement Agreement. Applicable federal environmental compliance obligations will be reflected in this modeling.[32]

#### 4. Facility Retirements

38. The Settling Parties agree that the Commission should approve retirement date of January 1, 2028 for Unit 3 of Tri-state's Craig Station ("Craig 3"). The Settling Parties agree that the Commission should approve a retirement date of September 15, 2031 for Unit 3 of the Springerville Generating Station ("Springerville 3"), subject to New ERA funding award as

[27] *Id*., ¶4.4.6.
[28] *Id*., ¶4.8.1.
[29] *Id*., ¶4.9.1.
[30] *Id*., ¶4.9.2.
[31] *Id*., ¶4.4.7.
[32] *Id*., ¶4.12.

requested from USDA and successful Tri-State negotiation of contractual agreements impacted by the unit's retirement.[33] Depending on whether New ERA funding is awarded to Tri-State, the Settling Parties agree to convene a meeting to discuss the modeling of Springerville 3, or for Tr-State to update common facilities costs for Springerville 3 and model the cost of any applicable federal environmental compliance obligations for Springerville 3 for Phase II modeling, as set forth in ¶4.6.1 of the Settlement Agreement.

### 5. Community Assistance

39. The Settlement Agreement also includes Section 5, which represents specific agreements between Tri-State and Craig/Moffat regarding community assistance.[34] While not joined by other Settling Parties, other parties convey their support or non-opposition for these provisions.

40. Tri-State agrees to provide a direct benefit payment for community assistance to Moffat/Craig in the amount of $5.5 million per year, to be paid between 2026 through 2029. The payment will go to an economic development fund established and administered by Moffat/Craig.[35]

41. Tri-State and Moffat/Craig agree that Phase I modeling identified the need for a gas plant in western Colorado with the potential to be cited in Moffat, consistent with Tri-State's siting study. Accordingly, in Phase II of its ERP, Tri-State will solicit bids for a gas plant to be sited in Moffat.[36] Tri-State and Moffat/Craig agree that no additional Commission approvals should be required for the gas plant if selected and approved in Phase II, however, Moffat/Craig agree to

[33] *Id*., ¶4.6.
[34] *Id*., ¶5.1.
[35] *Id*., ¶5.2.
[36] *Id*., ¶5.3.

support any further filings if required by the Commission, and Tri-State commits to provide drafting and/or administrative support for Moffat/Craig.[37]

42. Tri-State agrees to make certain "minimum backstop payments," to an economic development fund designated by Moffat/Craig. The backstop payments will total $48 million and will be paid out in decreasing increments, beginning in 2028 and ending in 2038. The minimum backstop payments are subject to offset for various items, including property tax revenues paid by Tri-State, federal or state grant funds, and other items agreed-upon items, as further set forth in ¶¶5.3.5, 5.3.6 and 5.3.7 of the Settlement Agreement.

43. In the evaluation and modeling of bids located in Moffat, Tri-State agrees to implement a $1/MWh price improvement over the life of a proposed project or contract.[38] The 2023 ERP Phase II "preferred portfolio" will be modeled with and without this price improvement.[39]

44. Within six months of the retirement of all three units at Craig Station, Tri-State will transfer to Moffat (upon consent of the Colorado River Water Conservation District), at no cost, storage water rights from Elkhead Reservoir, Second Enlargement (originally decreed in 02CW106), in an amount sufficient for the augmentation plan that is approved in Case No. 23CW3025 as determined by the Colorado Division of Water Resources and/or the Division 6 Water Court, and as further set forth in ¶5.5 of the Settlement Agreement.

45. Tri-State agrees to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3, as further set forth in ¶5.6 of the Settlement Agreement.

[37] *Id*., ¶5.3.3.
[38] *Id*., ¶5.4.1.
[39] *Id*.

46. Moffat/Craig and Tri-State agree to meet twice annually from 2025 to 2028 leading up to the Craig Station closure to identify opportunities where Tri-State's assets can be utilized to facilitate development in Moffat while also benefiting Tri-State's member systems, as further set forth in ¶5.7 of the Settlement Agreement.

47. Moffat/Craig agree not to seek further community assistance or workforce transition benefits from Tri-State in the future, or take positions on workforce transition reporting before a regulatory body, court, legislative body, or through discussions or communications with others that are inconsistent with the terms of the Settlement Agreement, as further set forth in ¶55 of the Settlement Agreement.

## II. ANALYSIS

### A. Burden of Proof

48. Except as otherwise provided by statute, the Administrative Procedure Act imposes the burden of proof in administrative adjudicatory proceedings upon "the proponent of an order."[40] The Settling Parties filed the Joint Motion and, as a result, bear the burden of proof.[41] The Settling Parties must establish by a preponderance of the evidence that the Settlement Agreement is just and reasonable and in the public interest. The Commission has an independent duty to determine matters that are within the public interest.[42]

### B. Modified Procedure

49. The Application, as modified by the Settlement Agreement, is uncontested. The Settlement Agreement was executed by each of the Settling Parties and is otherwise unopposed as

[40] Section 24-4-105(7), C.R.S.
[41] Section 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500 of the Rules of Practice and Procedure, 4 CCR 723-1.
[42] *See Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

is the Motion.[43] In addition, the parties agree that a hearing is unnecessary.[44] Finally, the Application and Settlement Agreement are supported by sworn testimony and attachments that verify sufficient facts to support the Application and Settlement Agreement. Accordingly, pursuant to § 40-6-109(5), C.R.S. and Rule 1403 of the Rules of Practice and Procedure, 4 *Code of Colorado Regulations* ("CCR") 723-1,[45] the Application, as modified by the Settlement Agreement, will be considered under the modified procedure, without a formal hearing.

### C. Analysis

50. Based upon substantial evidence in the record as a whole, the ALJ finds and concludes that the Settlement Agreement is just and reasonable and not contrary to the public interest. The ALJ shall approve the Settlement Agreement without material modifications and shall grant the Application, as modified and clarified by the Settlement Agreement and the testimony referenced therein.[46] In so doing, the ALJ approves Tri-State's assessment of need during the resource acquisition period, its plans for acquiring additional resources, and its proposed model contracts and evaluation criteria.

51. Paragraphs 4.2. and 5.3 of the Settlement Agreement (and the subparagraphs contained therein) thoroughly set forth the process and requirements for Phase II RFPs as well as the location (Moffat) of a gas plant for which Tri-State would solicit RFPs during Phase II. Multiple public comments addressed the public's concern as to the construction of a gas plant in Moffat.[47] Nonetheless, the ALJ is satisfied by the flexibility in the modeling requirements set forth

[43] Motion at 4-5.
[44] *Id*.
[45] 4 CCR 723-1.
[46] *See* Settlement Agreement, ¶4.3.7.
[47] *See, e.g.*, Public Comment Hr. Tr. for July 11, 2024 Public Comment Hr. at 13:1-8, 15:21-16:2, 20:1-13, and 35:12-21.

by the Settlement Agreement, which includes a requirement to model at least one portfolio with no new gas resources, should all other portfolios incorporate new gas resources.

52. Paragraph 4.2.2 of the Settlement Agreement set forth requirements regarding bid fees and bid security for Phase II RFPs. The ALJ finds that these provisions appropriately address concerns previously raised by COSSA/SEIA and Staff and are otherwise reasonable and not contradictory to the public interest.[48]

53. Paragraphs 4.2.7 – 4.2.10 of the Settlement Agreement addresses the New ERA Application. The New ERA Application was a primary area of concern for Staff prior to the execution of the Settlement Agreement.[49] The ALJs agree with the Settling Parties that the changes to Tri-State's Phase II RFPs provide reasonable flexibility while still ensuring that Tri- State can leverage federal funding. Moreover, Tri-State commits specifically to address grant flexibility with USDA and to provide informational updates to the Commission. The ALJ finds that the terms relating to the New ERA Application are reasonable and not contradictory to the public interest.

54. Paragraph 4.3 of the Settlement Agreement addresses the portfolios to be modeled by Tri-State in Phase II. The ALJ agrees with the Settling Parties that the portfolios to be modeled by Tri-State in Phase II promote flexibility and ensure the availability of sufficient options and combinations which would allow evaluation of backup options and help to inform the decision as to the need for additional gas resource.[50]

55. Paragraphs 4.4.1, 4.8.1, 4.8.2, and 4.8.3 of the Settlement Agreement address EWE Sensitivity. Notably, Tri-State will model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters. This approach is different than

[48] *See* Hr. Ex. 1501, p. 2:15-19; Hr. Ex. 203, p. 9:5-12; See also Hr. Ex. 122, pp. 5:22-6:16.
[49] *See* Hr. Ex. 200, pp. 38:15-39:11.
[50] *See* Hr. Ex. 903, p. 8:5-12; Ex. 402, pp. 8:19-9:2; Hr. Ex. 203, pp. 13:7-14:16; and Hr. Ex. p. 4:12-15.

the Phase I approach to EWE modeling. The ALJ finds that the EWE Sensitivity provisions are reasonable and not contradictory to the public interest.

56. As mentioned above, ¶4.1 of the Settlement Agreement states that the Settling Parties agree that Tri-State's 2023 ERP should be approved pursuant to Commission Rule 3605(g)(III), subject to the terms of the Settlement Agreement, without modification. The Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.[51] In its Answer Testimony,[52] LPEA/MPE stated that the Commission should "[d]irect Tri-State to model at least one 'lower load' scenario under which one or more additional members exit the Tri-State system, and consider the results of that scenario in the Phase I decision…"[53] As the lack of any objection by LPEA/MPE to the Motion or the Settlement Agreement and Tri-State's Rebuttal Testimony[54] suggests, this issue was satisfactorily resolved by Tri-State's commitment to update its load forecast during Phase II modeling to incorporate LPEA's departure beginning in April 2026 and the removal of Partial Requirements starting January 2026.[55] However, this commitment by Tri-State is not specifically set forth in the Settlement Agreement. Therefore, the Supplemental Direct Testimony of Lisa K. Tiffin, Hr. Ex. 110, which specifically addresses this commitment by Tri- State, will be incorporated by reference to the Settlement Agreement, as ordered below.

57. Paragraphs 4.4.4, 4.4.5, and 4.4.6 discuss modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants. The ALJ agrees that these modeling assumptions and

[51] Motion at 2; Settlement Agreement, ¶1.2.
[52] Hr. Ex. 1400.
[53] *Id*., p. 6:6-8.
[54] Hr. Ex. 113.
[55] *Id*. 8, 9-11.

obligations "align with the recommendations that WRA put forward in answer and cross-answer testimony, while reflecting a degree of compromise in the interest of settlement[;]"[56] are intended to be consistent with the New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, published in the Federal Register on May 9, 2024[.][57] Therefore, the ALJ finds that the provisions in the Settlement Agreement that address modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants, are reasonable and not contradictory to the public interest.

58. Paragraphs 4.4.7 and 4.4.8 of the Settlement Agreement sets forth guidelines for Tri-State's use of the EnCompass software to run its modeling. Staff notes, and the ALJ agrees, that the guidelines for Tri-State's use of the EnCompass software to run its modeling, as set forth in the Settlement Agreement, addresses Staff's prior concerns about Tri-State's EnCompass software configuration.[58] The ALJ finds that the provisions in the Settlement Agreement that address Tri-State's use of the EnCompass software to run its modeling are reasonable and not contradictory to the public interest.

59. Paragraph 4.5 of the Settlement Agreement sets forth Phase II bid generator interconnection criteria, including the requirement for bids for the years 2026-2027 to include generator interconnection queue position. The ALJ finds that that these criteria are reasonable and not contradictory to the public interest.

[56] Hr. Ex. 903, p. 7:18-20.
[57] Hr. Ex. 402, pp. 11:18-12:2 and Hr. Ex. 124, pp. 5:22-64.
[58] Hr. Ex. 203, pp.12:14-13:3.

60. Paragraph 4.6 of the Settlement Agreement states that the Settling Parties agree that the Commission should approve a retirement date of January 1, 2028 for Craig 3. The Settling Parties note, and the ALJ agrees, that the setting of a definite Craig 3 retirement date provides certainty for Moffat/Craig,[59] and while not easy to bear, is agreeable by Moffat/Craig.[60] The ALJ finds that a retirement date of January 1, 2028 for Craig 3 is reasonable and not contradictory to the public interest.

61. Paragraph 4.6 of the Settlement Agreement also states that the Settling Parties agree that the Commission should approve the retirement date of September 15, 2031 for Springerville 3, subject to certain conditions. Staff's concerns regarding modeling assumptions related to the cost of the retirement of Springerville 3 were appropriately addressed by the Settlement Agreement.[61] Further, Tri-State notes that the retirement date of Springerville 3 aligns with the New ERA application, which would facilitate the reduction of the cost of retiring Springerville 3 for Tri-State Members and enable exiting of contractual agreements to not result in undue financial impact on Tri-State Members.[62] The ALJ finds that a retirement date of September 15, 2031 for Springerville 3 is reasonable and not contradictory to the public interest.

62. Paragraph 5.6 of the Settlement Agreement discusses the requirements imposed on Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3. Moffat/Craig believe, and the ALJ agrees, that these requirements would enhance communication between Tri-State and Moffat/Craig and assist Moffat/Craig with local economic development planning efforts.[63] The ALJ notes that a single commenter in this

[59] Hr. Ex. 402, p. 11:10-14.
[60] Hr. Ex. 1603, p. 5:3-12.
[61] Hr. Ex. 203, p. 15:1-13.
[62] Hr. Ex. 123, p. 8:15-23.
[63] Hr. Ex. 1603, pp. 16:13-17:9.

Proceeding stated that the labor force of Craig 3 was excluded from the negotiation table as it relates to the Settlement Agreement. The commenter noted that while the Craig 3 labor force has a letter of agreement in place with Tri-State, the letter does not fully address workforce transition or timing; and the labor force has not had sufficient time to consider and respond to the terms of the Settlement Agreement.[64] The ALJ considered this public comment and finds that the Settlement Agreement appropriately addresses workforce transition issues in light of Tri-State's legal obligations and its continued willingness to engage in discussions regarding the local economy. Section 5 of the Settlement Agreement incorporates certain community assistance opportunities that were identified in the Informational Community Assistance Plan ("ICAP") developed by Moffat/Craig, Tri-State, OJT, CEO, and UCA.[65] However the ICAP includes other opportunities that are not limited to the actions of this Commission. Therefore, the ALJ finds that the commitments made by Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3 are reasonable and not contradictory to the public interest.

63. Paragraphs 5.2, 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.6, 5.3.7, 5.7, and 5.9, of the Settlement Agreement set forth the parameters for the monetary community assistance to be provided by Tri-State to Moffat/Craig. A significant number of public comments emphasized the support of individual customers and local officials for community assistance.[66] COSSA/SEIA note that they strongly support the "Direct Benefit" to Moffat/Craig that the community assistance provisions of the Settlement Agreement provide.[67] COSSA/SEIA further state that while they do

[64] Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 48:4-19, 49:1-7, and 49:19-50:4.
[65] Hrg. Ex. 1601, Att. CN-1, at p. 4-7.
[66] *See, e.g.*, Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 15:25-165, 19:14-19, 22:19-23:4, 25:19-26:13, 26:23-27:3, 28:10-21, 29:12-14, 30:9-14, 31:4-6, 32:19-33:11, and 53:10-54:2.
[67] Hr. Ex. 1501, p. 4:14-16.

not support the construction of a gas plant in Moffat/Craig, the Settlement Agreement provides for a competitive solicitation process that a natural gas plant will ultimately be constructed in Moffat/Craig.[68] Similarly, WRA states it supports the community assistance provisions of the Settlement Agreement, the community assistance provisions of the Settlement Agreement do not prematurely lock in the acquisition of new natural gas resources in Phase I of this Proceeding, and the construction of a gas facility in Moffat would provide an economic benefit to Moffat.[69] CEO, too, supports the community assistance provisions of the Settlement Agreement, as those are consistent with CEO's recommendations regarding Tri-State's Phase II gas resources modeling.[70]

64. Moffat/Craig state that community assistance provisions of the Settlement Agreement align with the ICAP process that originated from the Tri-State 2020 ERP Settlement Agreement and brings many of the ICAP Report's community assistance opportunities to fruition.[71] Moffat/Craig further state that Moffat/Craig have the most to lose in terms of annual tax base as a result of Colorado's transition away from coal, and the direct benefit payments and minimum backstop payments by Tri-State would help ease these impacts.[72] Moffat/Craig also state that the goal of Tri-State's community assistance fund is to attract new industries and support existing local businesses in the area to help with replacement tax base sources and job creation resulting from the loss of Craig 3 and two coal mines.[73] Lastly, Moffat/Craig state that tax base sources and job creation could be assisted by the establishment of a natural gas facility in Moffat, which also aligns with the need for a dispatchable energy resource in Western Colorado to ensure

[68] *Id*., p. 7:6-9.
[69] Hr. Ex. 903, p. 12:4-12.
[70] Hr. Ex. 402, p. 12:4-10.
[71] Hr. Ex. 1603, p. 8:10-13.
[72] *Id*., p. 10:1-9.
[73] *Id*., pp. 11:10-15, 13:13-14.

grid reliability.[74] Similarly, Staff "applauds" all parties involved in negotiating the community assistance provisions of the Settlement Agreement.[75] Tri-State states that the minimum backstop payments provisions of the Settlement Agreement, which allow for Tri-State's payments to be reduced based on Tri-State's investments in Moffat/Craig, can deliver value for Tri-State members and are otherwise aligned with Tri-State's functions as a non-for-profit organization.[76] The ALJ agrees with the justifications set forth above and finds that the community assistance to be provided by Tri-State to Moffat/Craig is reasonable and not contradictory to the public interest.

65. Paragraph 5.5 of the Settlement Agreement sets forth the parameters for the free transfer of Tri-State's water rights in Elkhead Reservoir to Moffat. Moffat/Craig state that securing Tri-State's water rights was the third-ranked CAO in the Final ICAP Report because the Yampa River upstream of the confluence with the Little Snake River, including all of its tributaries, was designated as "Over-Appropriated" and Moffat relies on water replacement augmentation through a lease agreement with the Colorado River Water Conservancy District.[77] Moffat/Craig further state that being able to secure the transfer of water rights from Tri-State would ultimately allow Moffat to expand housing opportunities for workers of any industry and attract new residents to Moffat.[78] The ALJ agrees that the free transfer of water rights from Tri- State to Moffat provides a substantial benefit to Moffat/Craig, is reasonable under the circumstances, and not contradictory to the public interest.

[74] *Id*., pp. 13:13-14:13.
[75] Hr. Ex. 203, p. 16:10-14.
[76] Hr. Ex. 123, p. 23:5-9.
[77] Hr. Ex. 1603, p. 15:8-18, *citing* Colorado Division of Water Resources, Over Appropriation of the Yampa River above the Confluence with the Little Snake River Letter (January 19, 2022), https://dnrweblink.state.co.us/dwr/0/edoc/3863278/DWR_3863278.pdf?searchid=20139195-951f-4bbd-a0fb-35562c8ddfee.
[78] *Id*., p. 16:2-9.

66. Paragraphs 5.3, 5.4.1, 5.4.2, and 5.4.3 of the Settlement Agreement set forth parameters relating to gas plant bid solicitation, energy cost, letters of support to be produced by Moffat in connection with Tri-State's 2023 ERP Phase II, 2027 ERP Phase I and II processes, and Moffat/Craig's advocacy in connection with any bids in Moffat County selected as part of Tri-State's preferred portfolio in Phase II of Tri-State's 2027 ERP. According to Moffat/Craig, Tri-State's application of a $1/MWh price improvement over the life of the proposed project and siting replacement for gas plant bids could assist local communities without having to take more extreme measures that threaten Colorado's marketplace.[79] According to CEO, the "price adder" set forth in the Settlement Agreement will help with bids located in Moffat not to be eliminated from the bid evaluation screening process before the non-price factor screen can be completed.[80] According to Moffat/Craig, gas plant bids siting replacement is in alignment with the third-party Generation Siting Study report authored by 1898 & Co., which selected a 239-acre Moffat County site in close proximity to Craig Station as the top location for a gas plant.[81] The ALJ agrees that the siting and price preferences given by Tri-State to Moffat in the context of the Settlement Agreement are a reasonable methodology that balances providing a locational preference with offering competitive flexibility, and thus are reasonable and not contradictory to the public interest.

67. Paragraphs 4.7.1, 4.7.3.1, and 4.7.3.2 of the Settlement Agreement set forth parameters relating to non-price bid factors for Tri-State's Phase II of the 2023 ERP. According to WRA, Tri-State's agreement to make information available to bidders regarding each of the listed non-price factors in the bid policy, including, where possible, the factors' relative weight,

[79] Hr. Ex. 1501, pp. 4:19-5:15.
[80] Hr. Ex. 402, p. 15:2-11, *citing* Hr. Ex. 400, Answer Testimony of Kathleen Gegner, p. 39:10-13.
[81] Hr. Ex. 1603, pp. 7:15-8:2, *citing* 1898 & Co. Generation Siting Study Report (Hr. Ex. 112, Tri-State Supplemental Direct Testimony of Chris E. Pink, Rev. 1, Attachment CEP-2 (Public Version of Generation Siting Study Report), at 37 (filed April 22, 2024)).

will improve transparency about the proposed framework at the outset of Phase I and satisfy WRA's concerns in this regard.[82] CEO states that it supports the non-price bid evaluation criteria set forth in the Settlement Agreement and explains that, as it understands it, tribal consultations, wildlife surveys, and/or plans to conduct such assessments, consultations, or surveys, will be offered on an informational basis and be otherwise consistent with Tri-State's existing and proposed processes, and that it is not creating additional requirements on bidders. The ALJ agrees that the non-price bid process outlined in the Settlement Agreement does not impose unreasonable requirements on developers, the process is otherwise reasonable under the circumstances, and is not contradictory to the public interest. The ALJ further notes that ¶4.7.1 of the Settlement Agreement, is consistent with §40-2-129(1)(b) and Rule 3605(h)(I)(A)(iii) of the Rules Regulating Electric Utilities, 4 CCR 723-3, which require Tri-State to provide the Commission with the best value employment metrics information provided by bidders as a part of its Phase II ERP Implementation Report.

68. Paragraph 4.9 of the Settlement Agreement sets forth three demand response requirements Tri-State must follow. According to WRA, the requirements on Tri-State to aim to control at least 5.5 percent of its Colorado peak load through demand response programs by 2030, although a compromise from WRA's initial proposal, represents a meaningful increase in Tri-State's future demand response capacity objectives.[83] According to Tri-state, the requirements set forth in ¶4.9 of the Settlement Agreement are "reasonable stretch goals." The ALJ agrees that the requirements set forth in 4.9 of the Settlement Agreement are reasonable and not contradictory to the public interest.

[82] Hr. Ex. 903, p. 9:11-17.
[83] Hr. Ex. 903, p. 8:15-22.

69. Paragraph 4.10 of the Settlement Agreement sets forth the minimum requirements for Tri-State's Phase II Implementation Report. CEO previously suggested, and supports, the requirements on Tri-State to provide the annual carbon dioxide and methane emissions in short or metric tons in its ERP Implementation Report, for each proposed Phase II portfolio and map all Phase II bids against an overlay of the EnviroScreen data layer that identifies DI communities.[84] The ALJ finds that the requirements set forth in¶4.10 of the Settlement Agreement are reasonable and not contradictory to the public interest.

70. Paragraph 4.11 of the Settlement Agreement sets forth criteria for Tri-State's Post-Phase II Transmission Injection Study. The ALJ finds that the requirements set forth in ¶4.11 of the Settlement Agreement are reasonable and not contradictory to the public interest.

71. Paragraphs 4.7.2, 4.9.3, 4.12 of the Settlement Agreement set forth certain requirements relating to Tri-State's 2027 ERP. According to WRA, the requirement on Tri-State to provide information in future annual progress reports on Regional Transmission Organization ("RTO") impacts to resource adequacy determination is "an appropriate starting place for understanding the impacts of RTO participation on electric resource planning," and complements other approaches for evaluating RTO participation and impacts on utility operations.[85] Tri-State explains that after the start of its participation in the Southwest Power Pool ("SPP"), which is scheduled for April 1, 2026, Tri-State will begin including certain SPP information in its ERP Annual Progress Reports, as specified in ¶4.12.3 of the Settlement Agreement.[86] The ALJ finds that the provisions of the Settlement Agreement relating to Tri-State's 2027 ERP are reasonable and not contradictory to the public interest.

[84] Hr. Ex. 402, p. 9:17-10:4.
[85] Hr. Ex. 903, pp. 10:16-11:2.
[86] Hr. Ex. 123, pp. 18:19-19:6.

72. Accordingly, in accordance with § 40-6-109, C.R.S., it is recommended that the Commission enter the following Order.

## III. ORDER

### A. It is Ordered That:

1. For the reasons stated above, the Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time, filed on June 27, 2024 by Tri-State Generation and Transmission Association, Inc., Highline Electric Association Highline, Poudre Valley Rural Electric Association, Inc., Y- W, Interwest Energy Alliance, Trial Staff of the Colorado Public Utilities Commission, the Office of the Utility Consumer Advocate, the Colorado Energy Office, Moffat County and the City of Craig, Office of Just Transition, the Colorado Independent Energy Association, Colorado Solar and Storage Association and the Solar Energy Industries Association, Conservation Coalition, and Western Resource Advocates (the "Settling Parties") is granted.

2. The Unopposed Comprehensive Settlement Agreement ("Settlement Agreement"), filed by the Settling Parties on June 27, 2024 is approved, consistent with the discussion above. The Settlement Agreement is attached to this Decision as Appendix A.

3. The Supplemental Direct Testimony of Lisa K. Tiffin, Hearing Exhibit 110 is incorporated by this reference into the Settlement Agreement and is included as Appendix B to this Decision.

4. The 2023 Electric Resource Plan Application, filed by Tri-State on December 1, 2023, as modified by the Settlement Agreement, is granted.

5. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

6. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a. If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b. If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

7. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Aviv Segev

Administrative Law Judge

ATTEST: A TRUE COPY

Rebecca E. White,
Director

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit BB: CoPUC, Decision No. C25-0892, issued on December 10, 2020,
in Proceeding No. 25V-0480E

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Decision No. C25-0892

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 25V-0480E

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IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS.

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# COMMISSION DECISION GRANTING JOINT PETITION WITH MODIFICATIONS AND ESTABLISHING PARTIES

Issued Date: December 10, 2025
Adopted Date: December 3 and 10, 2025

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## I. BY THE COMMISSION

### A. Statement

1. Through this Decision we grant, with modifications, the Joint Petition that Trial Staff of the Public Utilities Commission ("Staff"), the Colorado Energy Office, ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and Public Service Company of Colorado ("Public Service" or the "Company") (collectively, "Joint Petitioners") filed on November 10, 2025 ("Petition"). We specifically grant the requested variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") coal-fired facility from December 31, 2025, to December 31, 2026. In addition, we provide additional reporting and future filing direction regarding the proposed two-step process in the Petition and establish the parties to this Proceeding.

### B. Background

2. On November 10, 2025, Joint Petitioners filed the Petition seeking a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission

deems necessary, to modify the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") from December 31, 2025, to December 31, 2026.

3. Through Decision No. C25-0812-I, issued November 12, 2025, the Commission granted the Petition's request for a shortened notice and intervention period and established a deadline for responses to the Petition and replies to the responses. Interventions and responses, which were to be filed concurrently, were due on November 20, 2025, and any replies due on November 26, 2025.

4. Several parties filed timely motions to permissively intervene and responses on the November 20, 2025 deadline, and multiple public comments have been filed thus far.

5. Joint Petitioners filed a Joint Reply on November 26, 2025.

6. An unopposed late-filed motion to intervene was filed on December 2, 2025, by CORE Electric Cooperative ("CORE").

**C. Joint Petition**

7. The Petition requests a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761.[1] The requested variance would extend the planned retirement date of Comanche Unit 2 from December 31, 2025, to December 31, 2026. The Joint Petitioners assert that good cause exists to grant the variance and that the limited modification is in the public interest. The Petition also requests a shortened notice and intervention period of ten days and proposes a procedural schedule to allow for Commission deliberation and action by December 10, 2025.

8. Joint Petitioners contend that recent events have resulted in challenges to the planned retirement. As set forth in the Petition, these events fall generally into four categories: (1) the impact of the extended outage of Pueblo Unit 3 on Public Service's system; (2) increasing

[1] Issued September 10, 2018, in Proceeding No. 16A-0396E.

peak load growth in Public Service's territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies.

9. Joint Petitioners therefore seek relief in the form of a variance from the Commission's directive to file a certificate of public convenience and necessity ("CPCN") amendment to effectuate a retirement of the Pueblo Unit 2 by the end of this year, as well as any other requirements the Commission deems necessary.

10. Additionally, Joint Petitioners propose a two-step process for further evaluation in which the Company will provide two updates to the Commission on work in the extended review period. For the first step, the Company will provide a report to the Commission on March 1, 2026, which will include, among other things, an update on the repair and return to service status of Pueblo Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above.

11. For the second step, the Company commits to submitting an application on June 1, 2026, which would consist of any additional variances or resource approvals building on the report and will include, among other things, updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the Company's Near-Term Procurement, the Just Transition Solicitation ("JTS") Phase II resource solicitation, or other relevant proceedings.

**D. Establishment of Parties**

12. Under Rule 1200(a)(I), 4 *Code of Colorado Regulations* ("CCR") 723-1, parties shall include any person that initiates action through the filings of a complaint, application, or

petition. Therefore, Public Service, Staff, UCA, and CEO—as the Joint Petitioners—are parties to this Proceeding.[2]

13. The following parties filed timely motions for permissive intervention: the City of Boulder ("Boulder"); the Board of County Commissioners of Pueblo County, the City of Pueblo, and the Pueblo Economic Development Corporation (collectively, "Pueblo Intervenors"); GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar (collectively, the "Environmental Justice Coalition" or "EJC"); Western Resource Advocates ("WRA"); Colorado Energy Consumers ("CEC"); Natural Resources Defense Council and Sierra Club (collectively, the "Conservation Coalition"); the Colorado Renewable Energy Society ("CRES"); and Climax Molybdenum Co. ("Climax").

14. Boulder is a home rule city and municipal corporation and a large customer of Public Service. Boulder states its residents and businesses are also customers of the Company and that it has a longstanding interest in proceedings affecting electric generation, greenhouse gas emissions, and customer rates. Boulder asserts its climate goals depend on the decarbonization of Public Service's generation mix and that the early retirement of Pueblo Unit 2 was a key component of the Colorado Energy Plan portfolio it supported in the 2016 Electric Resource Plan ("ERP"). Boulder seeks to intervene to address the prudence, cost, and emissions implications of extending Pueblo Unit 2's operation.

15. The Pueblo Intervenors state they have substantial tangible and pecuniary interests in the continued operation of Pueblo Units 2 and 3. Pueblo Intervenors assert these units provide critical electric service to the Pueblo Steel Mill, a major employer and economic driver in the region, and contribute significantly to local tax revenues. Pueblo Intervenors argue that the

[2] Staff reiterates this point in its Notice to Rule 1007(a), filed on November 20, 2025.

outcome of this Proceeding will directly impact the economic stability of the community and the viability of ongoing industrial operations in Pueblo. Pueblo Intervenors support the variance and seek to ensure that community interests are adequately represented.

16. EJC represents community members in Pueblo and assert that the continued operation of Pueblo Unit 2 would disproportionately harm a historically impacted community already burdened by pollution from the Pueblo coal plant. EJC opposes the Petition as filed and instead supports an Alternate Plan that includes operational limits on Units 2 and 3, enhanced transparency, and a more robust process for evaluating the future of Pueblo Unit 3. EJC emphasizes the Commission's statutory equity mandate and urges action that prioritizes public health and environmental justice.

17. WRA is a nonprofit environmental advocacy organization focused on reducing greenhouse gas emissions and promoting clean energy across the Interior West. WRA states it has long participated in Commission proceedings, including the 2016 and 2021 ERP/Clean Energy Plan ("CEP") proceedings, and that it joined the settlement agreements that established the early retirement of Pueblo Units 2 and 3. WRA asserts the proposed variance could undermine those agreements and increase emissions, and therefore seeks to ensure that any delay in retirement is narrowly tailored and accompanied by operational limits and transparency measures to protect public health, the environment, and ratepayers.

18. CEC is an unincorporated association composed of various industrial and commercial customers of Public Service. CEC states its members operate facilities within the Company's service territory and are among its largest customers. CEC asserts the outcome of this Proceeding will directly impact its members' electric rates and service reliability, particularly due to the proposed extension of Pueblo Unit 2's retirement. CEC further states that it was a party to

the 2016 ERP and the 2021 ERP/CEP proceedings, and that the proposed variance would alter the assumptions underlying the Updated Settlement Agreement approved in those prior proceedings.

19. The Conservation Coalition is composed of two nonprofit environmental organizations with longstanding participation in Commission proceedings. The Conservation Coalition states it does not oppose a one-year variance for Pueblo Unit 2's retirement but objects to the breadth of the relief requested in the Petition. The Coalition supports an Alternate Plan that includes operational limits on combined generation from Pueblo Units 2 and 3, enhanced transparency and reporting, and a more timely and robust follow-on proceeding. The Conservation Coalition asserts its interests in environmental protection, public health, and ratepayer impacts would be substantially affected by the outcome of this Proceeding.

20. CRES is a nonprofit organization that promotes energy efficiency and renewable energy across Colorado. CRES states it represents a broad membership of individuals and businesses committed to accelerating the transition from fossil fuels to clean energy. CRES asserts that the proposed extension of Pueblo Unit 2's retirement would result in increased greenhouse gas and pollutant emissions and could delay the integration of renewable resources. CRES requests a more thorough, litigated process to evaluate the Petition and urges the Commission to ensure that any extension is supported by a complete evidentiary record.

21. Climax operates the Climax and Henderson molybdenum mines and is one of Public Service's largest electric customers. Climax states that its mining and milling operations depend on reliable and cost-effective electric service from the Company. Climax asserts that the outcome of this Proceeding will directly affect its operations due to potential impacts on system reliability and replacement power costs associated with the proposed extension of Pueblo Unit 2. Climax supports the requested variance with reservations and urges the Commission to clarify that

any costs incurred as a result of the extension or the Pueblo Unit 3 outage carry no presumption of prudence.

22. Pursuant to Rule 1401(c) of the Rules of Practice and Procedure, 4 CCR 723-1, persons seeking permissive intervention must show the following, in pertinent part:

> A motion to permissively intervene shall state the specific grounds relied upon for intervention; the claim or defense within the scope of the Commission's jurisdiction on which the requested intervention is based, including the specific interest that justifies intervention; and why the filer is positioned to represent that interest in a manner that will advance the just resolution of the proceeding. The motion must demonstrate that the subject proceeding may substantially affect the pecuniary or tangible interests of the movant (or those it may represent) and that the movant's interests would not otherwise be adequately represented.

23. We find that each party entity seeking timely permissive intervention has sufficiently demonstrated that this Proceeding may substantially affect its pecuniary or tangible interests, as is required by Rule 1401(c). Each also has demonstrated that its interests would not otherwise be adequately represented. Therefore, we grant each of the timely unopposed requests for permissive intervention.

24. On December 2, 2025, CORE filed a late-filed Motion to permissively intervene in this Proceeding. CORE includes in its filing that it is a wholesale purchaser of electric power and energy from Public Service, is a joint owner of the Pueblo Unit 3 facility with Public Service and Holy Cross Electric Association, Inc., and has significant contractual and regulatory relationships with Public Service. Thus, CORE includes that its direct, tangible, and pecuniary interests will be materially affected by the outcome of this proceeding, specifying that a variance in Comanche Unit 2's retirement date and the impact, if any, on changes to Comanche Unit 3's operations will affect CORE and its members. CORE states that, while untimely, its intervention is unopposed and will not broaden the scope of the Proceeding. CORE states that, following consideration of

the responses filed by potential parties, some parties indicate possible expansion of the Petition's scope to request operational changes at Unit 3, which could impact CORE as a joint owner.

25. Pursuant to Rule 1401(a) of the Rules of Practice and Procedure, 4 CCR 723-1, the Commission may, for good cause shown, allow late intervention, subject to reasonable procedural requirements. We find that CORE's late-filed intervention will not broaden the scope of this Proceeding or its process and otherwise meets the intervention standard set forth in Rule 1401. Therefore, we grant CORE's late-filed intervention.

### E. Party Responses

#### 1. WRA

26. WRA supports a limited variance to extend the retirement of Unit 2 but conditions its support on the Commission's adoption of the "Alternate Plan,"[3] which it developed in collaboration with the Conservation Coalition and the Environmental Justice Coalition. WRA summarizes the Alternate Plan as follows: (1) place a status quo operational limitation on the operation of Unit 2 and Unit 3, designed to limit the total, combined generation from Units 2 and 3 to 3,942,000 MWh in 2026; (2) provide transparent, regular reporting related to the continued operations of Unit 2 and Unit 3 and associated costs incurred; and (3) institute an appropriately accelerated process to determine Public Service's resource adequacy position, identify near-term solutions, and provide direction on the continued operation of Unit 2 and Unit 3.[4]

27. WRA emphasizes that the Alternate Plan is necessary to preserve the emissions reductions contemplated in prior Commission decisions and settlement agreements.[5]

[3] Attachment WRA-1 Alternate Plan.
[4] WRA Response at pp. 7-8.
[5] WRA Response at p. 8.

The Plan proposes a combined generation cap of 3,942,000 MWh for Units 2 and 3 in 2026, consistent with the 60 percent annual capacity factor limit previously approved for Unit 3. WRA argues this cap is essential to prevent an increase in emissions beyond what was previously authorized and to maintain the integrity of the Commission's prior resource planning decisions.

28. In addition to operational limits, WRA requests that the Commission require monthly reporting on a range of operational and financial metrics, including hourly generation, emissions, and costs associated with the continued operation of Unit 2 and the outage of Unit 3.[6] WRA also recommends that the Commission initiate a new application proceeding within 60 days of its decision on the Joint Petition to evaluate near-term resource adequacy and the future of Units 2 and 3.

29. Specifically, and as set forth in the Alternate Plan, WRA recommends the Company provide monthly reports on the 15th of each month with the following information:

(1) The MW produced each hour that Comanche 2 and Comanche 3 were operating;

(2) The total MWh produced by Comanche 2 and Comanche 3;

(3) The total $CO_2$, $SO_x$, $NO_x$, and PM10 emissions produced by Comanche 2 and Comanche 3;

(4) Any estimated future costs, and/or actual costs incurred, related to the outage of Comanche 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;

(5) Any updates on the repair and return to service status of Comanche 3, including the expected date for resuming operation;

(6) Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Comanche 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,

[6] WRA Response at pp. 12-13.

(7) Large Load Reporting:

- **a.** Information about actual load growth from large load customers, including MW and number brought online;
- **b.** Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
- **c.** Information about large load requests that have exited the queue, including MW and number.[7]

30. In addition, WRA argues the Commission should adopt the accelerated procedural framework set forth in the Alternate Plan. WRA asserts that adopting the Petition's proposed timeline for Step 1 and Step 2 would limit the Commission's ability to direct the Company to pursue alternative solutions.[8] Instead, through the Alternate Plan WRA recommends the Commission direct Public Service to file an application within 60 days of the Commission's final decision on the Petition. The purpose of such an application would be to receive Commission guidance on Public Service's near-term resource adequacy position for years 2026-2028 as well as on the future operation and life of Comanche 2 and 3. WRA contemplates that the Commission decision ruling on the application would address near-term capacity needs (2026-2028), whether to revise the retirement dates and operational restrictions for Unit 2 and 3, and the possible authorization for additional resource procurements.[9]

31. WRA strongly opposes the use of Unit 2 to serve new large loads, arguing that the Company's resource adequacy concerns stem solely from the outage of Unit 3 and not from broader system needs. WRA contends that the Petition's reliance on supply chain issues, load growth, and accreditation changes is an improper attempt to relitigate issues already addressed in the JTS and other proceedings.

[7] WRA Response, Attachment WRA-1 at pp. 2-3.
[8] WRA Response at p. 13.
[9] WRA Response, Attachment WRA-1 at pp. 3-4.

### 2. Conservation Coalition

32. Conservation Coalition requests the Commission deny the Petition and adopt the Alternate Plan, which is supported by Conservation Coalition, WRA, and EJC. Conservation Coalition states it does not object to a one-year variance from the requirements to retire Unit 2, but argues the Alternate Plan is necessary to resolve three problems with the Petition. First, Conservation Coalition argues the Petition would allow Unit 2 and Unit 3 to be run simultaneously with no limit on generation or emissions. Second, Conservation Coalition contends the Petition's proposition that the application proceeding to investigate dealing with near-term resource needs would not be filed until June 2026. Third, Conservation Coalition argues the Petition fails to address whether it is in the public interest to repair Unit 3 given its long-standing reliability and cost overrun issues.[10]

33. Conservation Coalition argues the only procedural and substantive basis for extending Unit 2 is the unexpected outage of Unit 3. They argue that Unit 3's outage is the new information that was not available during the JTS. According to Conservation Coalition, the other arguments put forth in the Petition—the increase in the Company's load forecast over time; supply chain and geopolitical delays in procuring resources from the 2021 ERP/CEP; and changes to the resource accreditation and planning reserve margin—are all improper attempts to relitigate issues that were addressed in the JTS.[11] Conservation Coalition states the Unit 3 outage is the only legally permissible basis for granting a variance, and Conservation Coalition reserves their rights to challenge a decision that grants a variance for any other reason.[12] Given that the only legitimate justification for extending Unit 2 is the unexpected outage at Unit 3, Conservation Coalition argues

[10] Conservation Coalition Response at pp. 1-2.
[11] Conservation Coalition Response at pp. 3-4.
[12] Conservation Coalition Response at p. 5.

that the combined generation from Unit 2 and 3 in 2026 must not be allowed to exceed what is permitted from Unit 3 in 2026.[13]

34. Conservation Coalition also argues that the two-step process proposed in the Petition—consisting of a March 1, 2026 report and a June 1, 2026 application—is insufficient and untimely. The Coalition characterizes the proposed timeline as "too little, too late" and asserts that the Commission should instead initiate a litigated proceeding as soon as possible to evaluate the least-cost, lowest-emission options for the continued operation or retirement of Pueblo Units 2 and 3 after 2026.[14] The Coalition contends that such a proceeding should address whether Unit 3 should be repaired at all, whether Unit 2 should continue to operate in lieu of Unit 3 after 2026, and what near-term capacity or energy needs exist, along with the most appropriate options for meeting those needs.[15]

35. According to Conservation Coalition, the Petition contemplates that Public Service may seek another variance in June 2026 to extend Unit 2's operation beyond 2026. Conservation Coalition notes that such a request would come only six months before the end of 2026 and would replicate the rushed nature of the current proceeding. In contrast, the Alternate Plan would provide the Commission with a more proactive and structured opportunity to evaluate near-term needs and the future of Units 2 and 3. The Conservation Coalition further observes that the June 2026 filing would occur after Unit 3 is expected to return to service, thereby presuming the prudence of the repair before the Commission has had an opportunity to evaluate alternatives. This timing, they argue, would also delay the acquisition of any necessary replacement resources.[16]

[13] Conservation Coalition Response at p. 7.
[14] Conservation Coalition Response at p 9.
[15] Conservation Coalition Response at p. 10.
[16] Conservation Coalition Response at p. 10.

36. Conservation Coalition also objects to the June 2026 filing framework on the grounds that it would leave the scope of the proceeding entirely to the discretion of the Company. Conservation Coalition urges the Commission to provide clear direction on the topics that must be addressed and the alternatives that must be modeled. Under the Alternate Plan, the Company would be required to present testimony and modeling results addressing updated estimates of energy and capacity needs for 2026 through 2028; an assessment of all reasonable supply-and demand-side options for meeting those needs; and modeling of portfolios that include new options for Units 2 and 3, such as early retirement or seasonal operations, compared to baseline expectations.[17] Conservation Coalition clarifies that the modeling should include scenarios such as extending Unit 2's operation beyond 2026 while retiring Unit 3 earlier than currently planned—*e.g.*, in 2028 or 2029—with or without seasonal operation of Unit 3 prior to retirement.

37. Conservation Coalition concludes by reiterating that the Commission should find there is no presumption of prudence for any costs associated with repairing Unit 3. They request that Public Service be required to notify the Commission of the estimated cost to repair Unit 3 before incurring such costs. Conservation Coalition further recommends that the Commission place the Company on notice that if it proceeds with repairs prior to conducting a modeling analysis demonstrating that such repairs are the least-cost option relative to alternatives, the Company may be at risk of a future disallowance.

**3. EJC**

38. EJC similarly recommends the Commission not approve the Petition but instead approve the Alternate Plan developed and supported by WRA, Conservation Coalition, and EJC. EJC argues that extending the life of Unit 2 will harm disproportionately impacted ("DI")

[17] Conservation Coalition Response at pp. 13-14.

communities in Pueblo., and states the Pueblo coal plants have emitted large amounts of pollution into the nearby community for more than five decades. EJC asserts that retiring Units 2 and 3 as planned will benefit the Pueblo community and reduce the pollution burdens that Pueblo has experienced since the 1970s.[18]

39. EJC notes that, under Senate Bill 21-272, the Commission has a statutory duty to minimize harms and correct the historical inequities experienced by DI communities such as Pueblo. To comply with its statutory equity mandate, EJC argues the Commission must thoroughly consider alternatives to address the outage of Unit 3 and approve an option that would best provide equity, address the historical inequalities, and minimize impacts and prioritize benefits in Pueblo. According to EJC, such alternatives include requiring operating guardrails that limit the overall generation at Unit 2 and Unit 3, utilizing market purchases while Unit 3 is offline, and reassessing the retirement date of Unit 3.[19]

#### 4. City of Boulder

40. Boulder argues the requested variance is the result of Public Service's inability to properly operate Unit 3, asserting there is no evidence suggesting that, but for Unit 3's outage, this variance would be necessary. Boulder notes the Joint Petitioners do not request the acquisition of any other generation resources to address the four identified events, and that the Joint Petitioners claim the cost to buy market power is higher than the cost to continue operations at Unit 2, yet provide no evidence or financial analysis to support this conclusion.[20]

41. Boulder agrees that the unplanned outage of Pueblo Unit 3, combined with delays in implementing new generation from the 2021 ERP/CEP, has left customers vulnerable to

[18] EJC Response at p. 4.
[19] EJC Response at pp. 6-8.
[20] Boulder Response at p. 3.

capacity shortfalls in 2026. Nevertheless, Boulder recommends that the Commission adopt several conditions to ensure ratepayer protection and to provide greater clarity regarding the Company's future resource planning.[21]

42. Boulder argues that ratepayers should be shielded from the cost increases associated with the failure of Unit 3 and the proposed extension of Unit 2. Specifically, Boulder recommends that the Commission prohibit Public Service from recovering any incremental costs related to the continued operation of Unit 2 or the repair of Unit 3 unless and until the Company demonstrates prudence in a future proceeding.[22] Boulder also supports the proposed March 1, 2026 Step 1 report and encourages the Commission to use that report to evaluate updated retirement dates for Pueblo Unit 3 and to explore additional demand response and distributed energy resources as near-and mid-term solutions.[23] However, Boulder expresses concern that the proposed June 1, 2026 Step 2 application timeline is unrealistic, and argues that the timeline does not allow sufficient time for the Commission to approve new resources and for those resources to be acquired and placed in service in time to address any capacity shortfall in 2026.[24] Boulder also notes that while the Petition suggests Public Service may seek expedited approval to acquire new resources, it fails to explain how such acquisitions would be feasible outside of the typical ERP, demand-side management, or renewable energy standard proceedings.[25]

43. Boulder further contends that the Joint Petitioners have not provided sufficient evidence to support their claim that a resource gap exists or that extending Unit 2 is the most cost-effective solution. Boulder recommends the Commission resolve these issues of Petition

[21] Boulder Response at p. 6.
[22] Boulder Response at p. 7.
[23] Boulder Response at p. 7.
[24] Boulder Response at p. 7.
[25] Boulder Response at p. 8.

adequacy before issuing a decision and certainly before the June 1, 2026 application is filed.[26] In addition, Boulder recommends that Public Service be required to acquire generation and storage resources to replace Unit 3 prior to its currently scheduled retirement date of January 1, 2031, and suggests that the Near-Term Procurement and JTS solicitations could be used to accomplish this.

44. Additionally, absent clear evidence in the Step 1 report that Unit 3 can return to service before the end of 2026, Boulder recommends that the Commission order Unit 3's immediate retirement.[27] Boulder also proposes that the Commission declare Unit 3 no longer "used and useful" and prohibit Public Service from earning its authorized return on equity until the plant is either returned to reliable operation or retired. Finally, Boulder encourages the Commission to consider a financial remedy to address the costs ratepayers have incurred due to the now-aborted retirement of Unit 2 and the Company's mismanagement of Unit 3.

**5. CRES**

45. CRES requests a hearing, discovery, and answer testimony to allow due process to investigate the Petition's claims. CRES acknowledges that such a fully litigated process would extend through the end of 2025 when Unit 2 is scheduled to retire and concludes that it may be prudent to grant the Petition only until more information is available and the evidentiary record for this Proceeding is complete.[28]

46. CRES also notes that allowing the 335 MW Unit 2 to continue operating for even one more year will emit a large amount of carbon dioxide and other harmful pollutants into the Pueblo community and surrounding area. Given the considerable consequences for air quality and

[26] Boulder Response at p. 8-9.
[27] Boulder Response at p. 10.
[28] CRES Response a p. 5.

public health, CRES requests that the Commission ensure that the Petition's claims are substantiated through a more traditional litigated proceeding. [29]

**6. CEC**

47. CEC argues that Unit 2's extension would not be necessary but for Unit 3's persistent operational failures, and generally supports granting the Petition to allow Unit 2 to continue operating, but argues the Commission should condition such a grant on several conditions.

48. CEC recommends the Commission impose several conditions to protect ratepayers from the financial consequences of Unit 3's outage. CEC notes that in prior instances of Unit 3 failures, the Commission has ordered disallowances through the Energy Cost Adjustment ("ECA"), and asserts that similar treatment is warranted here, where Unit 2 is being extended to serve as replacement power for Unit 3.[30] CEC argues there should be no presumption of prudence for any costs associated with Unit 2's extended operation, and that all costs related to Unit 3's outage should be disallowed. CEC recommends that the Company absorb all replacement power costs, including those associated with Unit 2, and return those costs to customers through the deferred balance in the next applicable ECA filing.

49. Specifically, CEC requests that the following rate-related conditions apply to the grant of the Petition: (1) all costs and investments associated with Unit 2's extended operation should be denied any presumption of prudence and evaluated in Public Service's next Phase I electric rate case; (2) Public Service must exclude from its revenue requirement all costs and expenses associated with Unit 3's outage in the test period, including gross plant, depreciation,

[29] CRES Response a p. 5.
[30] CEC Response at p. 6.

insurance, labor, and operations and maintenance; (3) Public Service must absorb all replacement power costs, including those from Unit 2 and any third-party sources, and flow those costs back to customers through the ECA; and (4) Public Service must include Unit 2's extended operation and emissions in any CEP compliance calculations and future emissions performance incentive mechanisms.[31]

50. CEC also raises concerns about the risk of over-procurement and overpayment for resources, given that the 2021 ERP/CEP modeling assumed Unit 2 would retire at the end of 2025. CEC warns of a scenario in which Public Service could simultaneously earn a return on Unit 2's extended operation, Unit 3 (once operational), and any new Company-owned generation approved to replace Unit 2. CEC questions whether the approved resource portfolio remains cost-effective in light of Unit 2's continued operation.[32]

51. To address these concerns, CEC recommends the Commission impose additional resource planning conditions as part of granting the variance. These include: (1) requiring Public Service to evaluate its loads and resource needs, accounting for Unit 2's extension and the results of the Near-Term Procurement, before commencing the JTS Request for Proposals; (2) requiring Public Service to evaluate and report on how the extension of Unit 2 affects the cost-effectiveness of its selected portfolios from the Company's 2021 ERP/CEP,[33] as modified by the CEP Delivery Plan and Neat Term Procurement results; and (3) granting any other relief the Commission deems necessary to hold ratepayers harmless from the effects of Unit 3's inoperability.[34]

[31] CEC Response at pp. 6-7.
[32] CEC Response at p. 10.
[33] Proceeding No. 21A-0141E.
[34] CEC Response at p. 7.

### 7. Climax

52. Climax supports granting the variance to extend Unit 2's retirement date to December 31, 2026, but argues the Petition lacks any substantial evidence to support the prudence or reasonableness of any costs associated with Unit 2's extension. Climax argues the Commission should clearly state that all costs incurred as a result of the Unit 3 outage and Unit 2 extension carry no presumption of prudence. If the Company proposes to recover these costs, it must clearly identify and distinguish them. According to Climax, Public Service must have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.[35]

### 8. Pueblo Intervenors

53. Pueblo Intervenors support the Petition, including the request to continue the operations of Unit 2 through next year and the expedited process and reporting requirements. They argue that the Company is facing a severe capacity shortage, and the Pueblo Steel Mill, an important industrial business in Pueblo, requires firm reliable electricity. Pueblo Intervenors argue the Company has been warning the Commission about its resource adequacy issues since February 2025 and that it would be reckless and dangerous to close Unit 2 with this type of resource shortage.[36]

54. Pueblo Intervenors further assert the coal units in Pueblo are necessary to provide electricity to one of the largest employers in the Pueblo Area—the Pueblo Steel Mill. They acknowledge the Pueblo Steel Mill is partly powered by a solar array and electric arc furnace but assert it still requires at times electricity from the Pueblo station. [37] Pueblo Intervenors add that

[35] Climax Response at p. 4.
[36] Pueblo Intervenors Response at pp. 2-3.
[37] Pueblo Intervenors Response at p. 4.

Unit 2 and the Pueblo Steel Mill provide family supporting jobs, and assert the continued operation of Unit 2 alone will also provide approximately $2.5 million a year in taxes for an additional year.[38]

### 9. Public Comments

55. The Commission received numerous public comments regarding the Petition reflecting a wide range of perspectives. Several environmental and community organizations, including 350 Colorado and Colorado Communities for Climate Action ("CC4CA"), oppose the extension of Unit 2 and call for stronger safeguards. 350 Colorado argues that the Petition lacks transparency and data, and characterizes it as an attempt to relitigate the JTS. The organization urges the Commission to deny the Petition or, at a minimum, require additional information before making a decision. CC4CA acknowledges that extending Unit 2 may be unavoidable but recommends that the Commission prohibit simultaneous operation of Units 2 and 3, cap cost recovery from ratepayers, and consider accelerating the retirement of Unit 3 if operational issues persist.

56. Other commenters, including the International Brotherhood of Electrical Workers ("IBEW") Local 111 and Colorado Concern, support the Petition. IBEW argues that closing Unit 2 at the end of 2025 would be reckless given current capacity shortages and emphasizes the importance of the jobs supported by the plant. Colorado Concern highlights the need for reliability and affordability amid rising energy demand and argues that approving the Petition demonstrates a disciplined approach to the energy transition. Several individual commenters also weighed in, with some expressing concern about ratepayer impacts and pollution, while others emphasized the need for reliable power and supported the extension.

[38] Pueblo Intervenors Response at p. 7.

57. Through its late-filed intervention and response, CORE claims that the Petition narrowly seeks a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission deems necessary to modify the plan to retire Pueblo Unit 2 from December 31, 2025 to December 31, 2026. CORE recognizes the importance of the continued operation of Pueblo Unit 2 to meet the needs of Public Service customers and does not object to the modification of the plan to retire Pueblo Unit 2 as requested. However, CORE argues that any consideration to changing the operations at Pueblo Unit 3 are outside the scope of the Petition's request and would require a separate application to allow for adequate time for all parties to prepare to respond and provide meaningful evidence.

**F. Joint Reply**

58. The Joint Reply states that few intervenors oppose the requested relief but rather most parties raise recommendations outside the narrow scope of this Proceeding. More specifically, the Joint Reply observes how several intervenors raise ratemaking issues, including arguments that the costs associated with repairing Unit 3 and extending Unit 2 should not receive a presumption of prudence. The Joint Reply notes, however, that the Petition does not seek a presumption of prudence but expressly states the Petitioners do not seek any ratemaking relief.[39]

59. The Joint Reply argues that issue of cost recovery associated with replacement power should be deferred to the relevant ECA and Purchased Capacity Cost Adjustment ("PCCA"). The Joint Reply adds that replacement power costs are currently unknown.

60. The Joint Petitioners oppose intervenor recommendations for additional reporting and an application filing prior to June 2026. The Joint Petitioners argue the two-step

[39] Joint Reply at pp. 2-3.

process—with a report in March and an application filing in June—is specifically designed to provide the Commission with an analysis of new resources projected to come on-line from the Near Term Procurement, JTS Phase II resource solicitation, or other relevant proceedings. In addition, the two-step process proposes to address operational concerns by first assessing operational parameters in Step 1 and giving the Company time to develop data-based recommendations to include in the application described in Step 2. The Joint Petitioners argue that—unlike the expedited track of the Alternate Plan—the June 1, 2026 application (Step 2) allows time to develop comprehensive solutions, for parties to provide meaningful input on these solutions, and for the Commission to consider alternatives. The Joint Petitioners add that neither the two-step process nor the Alternate Plan framework moves quickly enough to review options for Summer 2026 capacity needs.[40]

61. Regarding the monthly reporting the Alternate Plan requests, the Joint Petitioners agree that reporting is important. They argue, however, that so is taking time to assess options and present the result of that assessment to the Commission. They argue the cadence of the two-step process balances the need for reporting with the work required to assess and develop a plan to address resource adequacy needs. Nevertheless, in the Joint Reply the Company agrees to incorporate the reporting requested in the Alternate Plan in the Step 1 March report and the Step 2 June application filing, to the extent such information is available.[41]

62. The Joint Petitioners also oppose the Alternate Plan's operational limits on Unit 2 and Unit 3. They argue that addressing such operational limits is premature. The Joint Petitioners assert the Alternate Plan proposes the operational limits "without any analysis of current system

[40] Joint Reply at p. 6.
[41] Joint Reply at p. 5.

conditions or Comanche Unit 2's operating capabilities, and without taking into consideration the needs of the Company's system operators."[42]

63. The Joint Petitioners warn the Commission against relying on the loads and resources table put forth by WRA and Conservation Coalition, two of the three supporters of the Alternate Plan. They argue the loads and resources table has not been validated and it relies on assumptions that are likely to be contested in the fully adjudicated JTS proceeding.[43] More broadly, the Joint Petitioners caution against solely focusing on a loads and resources table when other metrics such as loss of load calculations are also relevant. The Joint Petitioners likewise ask the Commission to reject arguments that the Petition tries to improperly relitigate issues that could have been raised in the JTS. They note the JTS Phase I proceeding is still moving forward with RRRs and that the Petition's requested relief is narrow.[44]

### G. Findings and Conclusions

#### 1. Unit 2's Extension

64. Consistent with the Petition, we grant the requested variances from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Pueblo Unit 2 from December 31, 2025, to December 31, 2026. Extending Unit 2 is consistent with the arguments from Pueblo Intervenors and certain public commenters emphasizing the importance of reliable electricity. With this determination, we reject requests from CRES and others for a hearing, discovery, and answer testimony prior to a year-long extension of Unit 2. Such due process will be afforded in subsequent proceedings, including the Step 2 application filing and when Public Service seeks to recover costs associated with Unit 3's outage and the

[42] Joint Reply at p. 4.
[43] Joint Reply at p. 6.
[44] Joint Reply at p. 7.

extension of Unit 2. Given the prolonged, unplanned outage of Unit 3, we must move swiftly to allow Unit 2 to continue operating, but doing so in no way impedes the Commission from later finding that Public Service acted imprudently. Consistent with Climax's recommendations, if Public Service intends to recover the costs associated with Unit 3's breakdown and Unit 2's extension, the Company will have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.

65. As part of our decision to grant the requested variance, we find that Unit 3's prolonged, unplanned outage is the single justification for extending Unit 2. As set forth by intervenors like WRA, Conservation Coalition, Boulder, and CEC, the Joint Petitioners have failed to demonstrate that the other reasons set forth in the Petition—supply chain and geopolitical issues, changes to the Company's resource accreditation methodology, and increasing peak demand—justify Unit 2's extension.

66. Regarding increasing peak demand, the most recent forecast provided in the Petition shows a 2026 peak demand of about 7,150 MW.[45] However, the Company's preferred updated base forecast that it endorsed in the JTS Rebuttal had a higher 2026 peak demand of 7,235.[46] Even though the Company had a higher demand forecast in its JTS Rebuttal, Public Service never requested or even suggested that it would need to extend Unit 2 to maintain resource adequacy. To be sure, Public Service raised concerns with its capacity position in recent proceedings, including in the JTS, but the Company never suggested the retirement date of Unit 2 should be reconsidered until now. An extension of Unit 2 was unnecessary until Unit 3 suffered its prolonged outage.

[45] Petition at p. 5.
[46] Hr. Ex. 117, Ihle Rebuttal, p. 30 filed in Proceeding No. 24A-0442E.

67. A similar analysis applies to the Petition's arguments regarding supply chain and geopolitical issues and modifications to its resource accreditation methodology. The Petition provides no new evidence regarding supply chain and geopolitical issues but simply states that "[t]he Company addressed this in the CEP Delivery Plan in September 2024."[47] The Petition adds that while the CEP Delivery Plan assists with geopolitical and supply chain issues, it does not cure them. Although not recounted in the Petition, geopolitical and supply chain issues were also an issue in the JTS—as demonstrated by issues such as the tariff passthrough mechanism the Phase I Decision adopts. In neither the CEP Delivery Plan nor the JTS did Public Service raise the possibility that geopolitical and supply chain issues could necessitate the extension of Unit 2. Again, Unit 2's extension was unnecessary until Unit 3 went down.

68. The Petition similarly provides no new information regarding the modified resource accreditation methodology. Instead, the Petition recounts how it worked with a consultant in the JTS proceeding to update its resource accreditation methodology. The Petition does not indicate that there have been subsequent changes since the JTS Phase I Decision but simply states that the updated resource accreditation methodology "affects the Company's loads and resource balance."[48] Although the Company cited its updated resource accreditation methodology in both the CEP Delivery Plan and the JTS as a justification for additional resources, Unit 2's extension was never raised as a potential solution until Unit 3 broke down.

**2. Two-Step Process**

69. On balance, we largely adopt the two-step process put forth in the Petition. This includes the March 1, 2026 report and analysis (Step 1) and the application filing the

[47] Petition at p. 5.
[48] Petition at p. 6.

Company must file no later than June 1, 2026 (Step 2). Although we share the frustrations expressed by several intervenors with the June 2026 date for the Step 2 application filing, we are sensitive to the Company, CEO, UCA, and Staff's timeline recommendations. In addition, even with an early 2026 filing as the Alternate Plan requested, the Commission would likely not be in a position to proactively determine whether repairing Unit 3 is prudent given the Company's expectations that Unit 3 will be fully repaired and return to service in June 2026. To be clear, the Step 2 application filing must be filed no later than June 1 2026, but we encourage and would accept earlier filings. The decision not to make earlier filings may in and of itself be imprudent if there are approvals or actions the Company should have raised earlier to the Commission and for party consideration.

70. While we do not require the expedited application filing requested in the Alternate Plan, we again emphasize that there is no presumption of prudence at this time for the repair of Unit 3 or operation of Unit 2. Public Service cannot assume that repairing Unit 3 is a prudent approach if better alternatives are available. For example, if continuing to operate Unit 2 through 2030 together with market purchases and additional demand side resources is a more cost-effective option than repairing Unit 3, Public Service would be at risk for disallowance if it brings Unit 3 back to service.[49] This is consistent with Boulder's recommendation to specifically seek out demand response and distributed energy resources to meet near- and mid-term resource adequacy. In sum, it appears the Company has decided to repair Unit 3 without first seeking guidance from the Commission—despite the plant's well-documented reliability issues, the fact that Unit 3 is slated to retire in January 2031, and the fact that the settlement agreement from the 2021 ERP

[49] Even aside from the issue of whether there are better alternatives to repairing Unit 3, Public Service may be at risk for disallowance if the Commission finds that the Company's imprudent operation of the plant led to its outage.

significantly limits the plant's annual capacity factor in its remaining years of life. Public Service's strategy on Unit 3 puts the Company at risk if its actions are later found to be imprudent.

71. Nevertheless, we are not deciding at this juncture to disallow the replacement power costs and repair costs associated with Unit 3's outage. Doing so here would be premature. We thus deny CEC's request to apply several rate-issue conditions such as directing that the Company exclude from its revenue requirement in the next electric rate case all costs and expenses associated with Unit 3's outage as well as Boulder's recommendations to prohibit cost recovery associated with any incremental costs of extending Unit 2's operations or repairing Unit 3. While the Commission may ultimately disallow such costs, Public Service does not request cost recovery in this Proceeding, and we lack the necessary information to make such findings.

### 3. Additional Reporting

72. Although we mostly accept the Petition's proposal for the two-step process, we find intervenor arguments regarding the need for additional reporting persuasive. In particular, we largely adopt the requested reporting set forth in the Alternate Plan. The Joint Petitioners provide little reasoning for their opposition to the reporting requests, but they imply that such reporting will leave insufficient time to assess options and present the results of that assessment to the Commission.[50] We find, however, that the requested reporting information will likely prove useful in future proceedings, including cost-recovery proceedings and the June 1, 2026 application proceeding. Proactively providing this information to the parties will hopefully make such future proceedings more expedient and effective. We acknowledge the Company's statement that it will include the requested information in the Step 1 and Step 2 filing, to the extent available, but we are persuaded that monthly reports will be more helpful to the Commission and parties.

[50] Joint Reply at p. 5.

73. While we generally adopt the cadence and substance of the reporting set forth in the Alternate Plan, we find certain clarifications to be necessary. First, we clarify that any estimated material future capital costs for the repair of Unit 3 must be reported to the Commission before such costs are obligated. Second, for the information concerning large loads, Public Service must include such data in the same format as it presented in the JTS proceeding in which each large load is correlated to its industry, the probability of the load materializing, the requested in-service date, and the forecasted load by year through 2040.[51] In addition, out of all of the large loads listed, Public Service must clearly identify those that meet the Phase I Decision's requirements to be included in the base load forecast (*e.g.*, those loads that have executed an electric service agreement and interconnection agreement with the commercial principles including the fair notice provision).[52]

74. Thus, Public Service shall provide monthly reports beginning on January 15, 2026, that contain the following information:

- The MW produced each hour that Unit 2 and Unit 3 were operating;
- The total MWh produced by Unit 2 and Unit 3;
- The total $CO_2$, SOx, NOx, and PM10 emissions produced by Unit 2 and Unit 3;
- Any estimated material future capital costs for the repair of Unit 3, before they are obligated;
- Any additional future or actual costs incurred related to the outage of Unit 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;
- Any updates on the repair and return to service status of Unit 3, including the expected date for resuming operation;

[51] *See* Hr. Ex. 141, Updated Base Forecast Large Load filed in Proceeding No. 24A-0442E.
[52] *See* Decision No. C25-0747 at ¶ 68 issued in Proceeding 24A-0442E on November 6, 2025.

- Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Unit 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,
- Large Load Reporting:
  - **a.** Information about actual load growth from large load customers, including MW and number brought online;
  - **b.** Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
  - **c.** Information about large load requests that have exited the queue, including MW and number.[53]

75. The Commission emphasizes that simply complying with these reporting requirements does not constitute a request for Commission approval. As a corollary, any Commission inaction regarding the submitted information is in no way tacit approval of the information or expenditures. If Public Service desires Commission guidance on its activities regarding Unit 3's outage, the Company must make an appropriate application filing.[54]

76. In addition to the reporting set forth above, Public Service shall describe in its March 1, 2025, Step 1 report whether the outage at Unit 3 and the continued operation of Unit 2 impairs the ability of the Arroyo 2 solar facility—or any other resource—from delivering energy as planned. For instance, it appears the Arroyo 2 solar project was designed to use the same transmission capacity as Unit 2: "The Arroyo 2 Project … will utilize the replacement interconnection rights that will become available due to the planned retirement of Comanche Unit 2 at the end of 2025."[55] If Arroyo 2 or any other resources cannot be operated as planned due

[53] *See* WRA Response, Attachment WRA-1 at pp. 2-3.

[54] Should the Commission require additional information, process, or directives regarding the Step 2 application filing or other necessary direction following review of the reporting provided, it will do so through separate order, if needed.

[55] Hr. Ex. 101, Pascucci Direct, p. 11 filed in Proceeding No. 24A-0140E.

to Unit 3's outage or while Unit 2 is operating, this is potentially another cost of Unit 3's breakdown that Public Service must track.

### 4. Operational Limitations on Unit 2 and Unit 3

77. One of the main requests of the Alternate Plan backed by WRA, Conservation Coalition, and EJC, is to place an operational limitation on Unit 2 and Unit 3 so that the two units together could not generate more than 3,942,000 MWh in 2026. This 3,942,000 MWh limit is what Unit 3 could produce in 2026 given its 60 percent annual capacity factor limit agreed upon in the 2021 ERP. The Joint Petitioners oppose the operational limitation, arguing that it is premature and that further evaluation is necessary before the Commission imposes such limits.

78. We agree with arguments from intervenors that the various settlements contemplating the closure of Unit 2 and the operational restrictions on Unit 3 should be respected.[56] Public Service never suggested in the CEP Delivery Plan or the JTS that the Company would need to surpass the 60 percent annual capacity factor limit on Unit 3 in order to maintain resource adequacy. Nor has the Company set forth sufficient evidence in this Proceeding to justify this result. Given that Unit 2 and Unit 3 are now intended to work together to do the work that Unit 3 would have done but for its closure, it is reasonable to apply Unit 3's operational limit from the 2021 ERP to both units. Finally, the Joint Petitioners' argument to wait until the Step 2 application filing in June 2026 is unhelpful. Even with a 120-day expedited schedule, the Commission would not issue a decision on the Step 2 application filing until October, and RRR could push a final decision into late November. This would leave approximately one month in 2026 to implement operational limitations on Unit 2 and Unit 3.

[56] Chair Blank dissents from this point and would require additional reporting on the collective operation of Unit 2 and Unit 3 but would not impose the operational limitation. Chair Blank expresses concerns about non-economic dispatch and how much the operational limitation would cost.

79. We therefore approve the 3,942,000 MWh operational restriction at Unit 2 and Unit 3 as proposed in the Alternate Plan. If Public Service has concerns with the 3,942,000 MWh limitation, the Company may file an appropriate request supported by testimony and other evidence. This pathway maintains the emissions status quo the parties agreed upon in the respective settlements while appropriately putting the burden on the Company to explain why exceeding the agreed upon limit is in the public interest.

### 5. CEC's Resource Planning Recommendations

80. As set forth above, CEC recommends the Commission impose certain resource planning conditions, warning of a situation in which Public Service can simultaneously earn a return of and on its investment in Unit 2's extended operation, the resources acquired to replace Unit 2, and Unit 3 (once operational).[57]

81. We decline to adopt CEC's resource planning conditions. The resources selected in the 2021 ERP/CEP and that will be selected in the JTS will serve Public Service's system for 10 years or more. While the extension of Unit 2 changes the Company's loads and resources table in the short term, it is unlikely to have a significant impact on long-term resources acquired in these proceedings, especially if the Company remains in a capacity short position. Unit 2 running together with Unit 3 would have a more significant impact, especially if both are kept operating past 2026. At this point, however, the Commission and parties do not have sufficient information to assess the likelihood of this situation.

[57] CEC Response at p. 10.

## II. ORDER

### A. The Commission Orders That:

1. The Motion seeking to permissively intervene filed by the City of Boulder on November 20, 2025, is granted.

2. The Motion seeking to permissively intervene jointly filed by the Board of County Commissioners of Pueblo County, City of Pueblo, and Pueblo Economic Development Corporation, on November 20, 2025, is granted.

3. The Motion seeking to permissively intervene filed jointly by GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar on November 20 2025, is granted.

4. The Motion seeking to permissively intervene filed by Western Resource Advocates on November 20, 2025, is granted.

5. The Motion seeking to permissively intervene filed by Colorado Energy Consumers on November 20, 2025, is granted.

6. The Motion seeking to permissively intervene filed jointly by Sierra Club and Natural Resources Defense Council on November 20, 2025, is granted.

7. The Motion seeking to permissively intervene filed by the Colorado Renewable Energy Society on November 20, 2025, is granted.

8. The Motion seeking to permissively intervene filed by Climax Molybdenum Company on November 20, 2025, is granted.

9. The late-filed Motion seeking to permissively intervene filed by CORE Electric Cooperative on December 2, 2025, is granted.

10. The Joint Petition filed by Trial Staff of the Public Utilities Commission, Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado on November 10, 2025, is granted with modifications, consistent with the discussion above.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective immediately upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING December 3 and December 10, 2025.**

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK[58]

MEGAN M. GILMAN

TOM PLANT

Commissioners

COMMISSIONER ERIC BLANK
DISSENTS, IN PART

[58]Eric Blank dissents in part.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit CC: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)

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# Electric Energy and Demand Forecast

This section summarizes Tri-State's approach to development of its base electric energy and demand forecast, and forecast variations, for Phase I ERP scenario modeling. Key assumptions and resulting forecast data are provided, including for compliance with Commission Rule 3605(b).

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Colorado PUC E-Filings System

## Description of Process

This subsection addresses forecast requirements in Commission Rule 3605(b)(IV). The base long-term load forecast is prepared utilizing input from each of Tri-State's Utility Member Systems every year. Tri-State has a four-state service territory, with 42 Utility Member Systems[1] and each consists of up to nine retail classes in which a bottom-up forecast methodology is employed.

## Inputs

### *Gross Load Forecast*

The primary source for historical retail data by each class of consumers is Rural Utilities Service (RUS) Form 7, which is compiled by each of Tri-State's Utility Member Systems after the end of each calendar year. Information by month and class on the number of accounts, energy use per account, total energy, and the average price of electricity is collected for each Member. In addition, data on large commercial accounts is gathered on RUS Form 345. Historical wholesale Utility Member System hourly demand and load shapes are generated using data obtained from Tri-State's member billing system, which pulls data from delivery point meters on Tri-State's system.

Weather data from 20 weather stations within Tri-State's region is supplied through DTN Meteorlogix. Tri-State's database includes temperature, heating and cooling degree-days, and precipitation. Weather normalizations of this data are used in forecasting models (defined as 10-year average values).

Tri-State obtains economic and demographic data from Woods & Poole Economics, Inc. (W&P) for the county/counties that make up each Utility Member System. The majority of data from W&P originates with the Bureau of Economic Analysis (BEA), an agency within the U.S. Department of Commerce. All projections of economic and demographic data have been performed by W&P. Tri-State uses more than 20 measures demographic data as well as of employment and income activity by sector from the W&P data set.

Tri-State incorporates data from ITRON's Residential Statistically Adjusted End-Use (SAE) models for the West Mountain region into residential use-per-customer forecasts. Residential use-per-customer estimates include projections related to household thermal efficiency, heating and cooling unit saturation, appliance efficiency, lighting efficiency, and household size.

Tri-State periodically conducts a Residential End-Use Survey to identify residential characteristics specific to each Member. Questions include data on type of heating and cooling technology, appliance data, and thermal shell metrics. Heating and cooling saturations by member as of the survey year are calibrated using the percent growth in technologies for the Rocky Mountain Region from the SAE model.

The electricity that Tri-State Utility Member Systems provide to their Member Consumers (retail customers) often competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and

[1] Beginning February 1, 2025, Tri-State anticipates having 39 Utility Member Systems.

Annual Energy Outlook. Tri-State bases its price projections for each of these alternative fuels on information from the EIA. These price projections for alternative fuels are exogeneous drivers that are available for use in econometric model development and are incorporated as a variable into some member estimates for residential and commercial classes.

Using annual historical data from 2003 through 2021, historical trends, as well as future projections for demographic and economic drivers, lighting efficiency and household heating and cooling profiles, Tri-State's statistical models estimate future gross load and demand.

### *Input Adjustments to Gross Load Forecast*

While the above inputs are used to derive Tri-State's gross load and demand by member, additional inputs are collected to calculate adjustments related to partial requirements, distributed generation, energy efficiency, and beneficial electrification.

Tri-State allows Utility Members to serve a portion of their load from non-Tri-State resources, including partial requirements and distributed energy generation.

Partial Requirements[2] reflects a reduction in Utility Member load due to the election of members to buy out of a portion of their wholesale contract. Tri-State offers Utility Members two versions of this. The first is "MAX," which allows a member to source a fixed amount of around the clock demand and energy from another provider. To estimate load for this option, Tri-State uses the expected contract start date, amount of demand, hours per month, and region. The second option, "MARS," allows a member to elect to purchase energy from another provider using supply of a utility-scale resource. To estimate MARS load, Tri-State collects data on the expected contract start date, name and type of resource, and region. In addition, Tri-State collects three-year historical average hourly load profile for a resource of similar size in close proximity for use in shaping the estimated hourly partial requirements output.

To model distributed generation resource load and demand, Tri-State utilizes the contract dates, resource type (such as wind, hydro, tracking solar, or non-tracking solar), nameplate, and average hourly history for three to five years.

Estimates for energy efficiency and beneficial electrification are calculated using ERP targets and data provided by a third-party vendor. They are layered onto load estimates – with energy efficiency being a reduction in energy and beneficial electrification increasing electricity – during post-processing by other modeling groups.

Demand response is modeled as a generating resource; Attachment B of the ERP Report (LKT-1) provides additional details related to these estimates. In the financial estimates, which are concerned with energy billed, demand response energy is shown *net of any load shifts*. That is, if load is shifting from a peak hour to a non-peak hour, it does not impact the amount of energy billed to a customer and is not shown in

[2] After beginning of Phase I scenario modeling, FERC accepted the withdrawal of Tri-State's partial requirements filing. Tri-State is working with its Members to revise the approach to partial requirements supply. Phase I scenario modeling reflects initial partial requirements elections and methodology.

billing estimates. Only the net change in energy billed to customers will be reflected in demand response aggregates in financial modeling.

## Forecasting Process

### *Gross Load Forecast Process*

The nine retail classes include residential, seasonal, irrigation, small commercial, large commercial, public authorities, streetlights, resales to RUS, and resales to others. Each retail class, with the exception of large commercial, is broken into the number of customers and use-per-customer, which are then modeled separately and aggregated to arrive at forecast energy. By separating the demand forecast into the use per-customer and customer components, Tri-State can better distinguish between the trends driving growth in the number of customers versus technology or weather impacts on customer-level usage. There is also a separate category for the Utility Member's own use.

For all forecasts except for Large Commercial and Own Use, the number of customers and the use-per-customer are projected using a combination of econometric techniques, time series regressions, and simple trend analyses that generally utilize 20 years of history. Time series regressions typically utilize Auto Regressive Integrated Moving Average (ARIMA) modeling over a period of 20 years of historical data. If a defensible and statistically significant model can't be found, analysts may use an average, often over 5 years. Energy for these classes is derived by multiplying the number of customers by use-per-customer. The Large Commercial class energy forecast used in the ERP are derived from the combination of a statistical regression model over 20 years of history and Form 345 projections, whichever is greater. Own use only has one customer, the Utility Member, and Tri-State forecasts the energy directly based on historical trend.

Forecasts of residential customers are derived through multivariate regression models with explanatory variables including, but not limited to, population, employment, and income. Other models for the number of customers may rely on forecasted employment, trend, or a historical average.

Use-per-customer is also modeled using econometric models or weighted averages. Multivariate regressions on use-per-customer generally consider trend and weather; residential use-per customer forecasts incorporate data on area lighting and appliance efficiency, heating and cooling profiles, and building thermal efficiency that are derived from end use surveys and the ITRON's SAE models for the West Mountain region. If there is not a good model fit for use-per-customer for the various classes, a five-year average is generally utilized as a default. The residential use forecast is an exception and utilizes the end-use model when possible.

Once the nine classes and own use are forecasted, Tri-State aggregates them and then applies a retail loss factor that is generally an average from recent history. Retail losses are added to the aggregate energy by class to arrive at total annual energy purchases for each Utility Member System across the resource planning period (RPP). For each member, the monthly load shapes are based upon the Seasonal Index method utilizing a 2x12 centered moving average. Monthly forecasts are then used to generate a calendarized hourly dispatch based upon on the most statistically representative months from the last five years of history. After all estimates are generated, a draft report is then sent to each Member for

their review and feedback; periodically Tri-State will incorporate Member-requested adjustments that reflect each Member's intimate knowledge of conditions in their area.

Once the forecasts are finalized and completed for each Utility Member System, the final step is forecast aggregation to arrive at gross forecasts for state, planning region, and Tri-State as a whole. During the annual update process, for members that are split either between a state or grid boundary, Tri-State uses an average of the last three calendar years to determine state and planning regions for the forecast. These splits are generally carried forward in forecast estimates for the entire planning period until a new full calendar year is available.

### *Gross Demand Forecast*

The projected values of the Member Coincident Peak (MCP) gross demands are based upon an hourly load forecast. Hourly loads are generated for each calendar month by applying the projected purchased energy requirement to a corresponding normalized historical load duration curve. The resultant hourly loads are dispatched chronologically based upon known historical loads and seasonal indices from a calendarized representative month. Once individual members' hourly demand forecasts have been determined, they are summed to arrive at a total Tri-State hourly load forecast (using a bottom-up approach), allowing the system coincident peak demand to be established.

The peak period used for billing is defined as the period between 12:00 (noon) and 10:00 PM, Monday through Saturday, except certain holidays. The Tri-State aggregate billing peak is the sum of the individual member peaks from the hourly demand forecasts, which occur within the defined peak period. The Tri-State Coincident Peak (TCP) for capacity planning is the highest hourly sum of Utility Member System hourly demand forecasts. Tri-State's peak occurs in July throughout the planning period, as Tri-State is a summer peaking system. Of note, Tri-State aggregates demand by state and planning region in a manner similar to the aggregation for energy. Hourly profiles for energy efficiency, partial requirements, beneficial electrification, and distributed generation are layered onto gross demand forecasts within the expansion and production cost models. This total demand is used in the expansion plan for resource planning and transferred to the Hyperion financial model in a manner similar to energy, to arrive at demand served by Tri-State.

Additional details on energy efficiency, demand response, and beneficial electrification modeling assumptions can be found in Attachment B and G-3 of the ERP Report (LKT-1).

### *Process for Calculating or Incorporating Load Forecast Adjustments*

Several adjustments are made to gross load to arrive at load served by Tri-State, including distributed generation, partial requirements, energy efficiency, and beneficial electrification.

Distributed generation (DG) is a subtraction from gross load to arrive at the Utility Member load served by Tri-State. Distributed generation forecasts consist of energy and demand forecasts on a project level for member self- supply options, including Board Policy 115 (renewable self-generation on Member Systems), Board Policy 119 (community solar on Member systems). To calculate energy served by behind the meter or distributed generation resources, Tri-State estimates load using load shapes based on a three- year hourly average. For new or prospective distributed generation resources, rather than using the three-year history for the resource, Tri-State forecasts the energy and demand by scaling the three-

year historical average hourly load profile by the relative nameplate size to an existing resource in close proximity and same technology type (for example, wind, tracking solar, non-tracking solar, hydro) over the contract period.

As of February 2023, Members have over 66 renewable or distribution generation projects, totaling 143 MW of capacity and capable of producing ~300 GWh/year are operating or under development. By capacity, approximately 85% of Utility Member System distributed generation is located in Colorado and 14% is in New Mexico. By technology, 81% of distributed generation is solar, 6% is wind, and 7% is waste heat, with the remaining comprised of hydro or landfill methane.

The calculation of Partial Requirements adjustments depends on whether the Member elected the MAX or MARS Partial Requirements option. For the MAX option, Tri-State uses the around-the-clock demand elected by the member and derives energy by multiplying the demand by the number of hours in the month. Under the MARS option, Tri-State estimates partial requirements energy by scaling the three-year historical average hourly load profile for a similar type resource in close proximity to the planned resource to the nameplate of the expected resource; the existing MARS Partial Required election is currently modeled as a tracking solar resource. Once Partial Requirements are operational, for MARS, Tri-State would use the three-year historical average to estimate the energy and demand. As Partial Requirements reflects energy that would be provided to the Member by third-party providers, the energy and demand is a reduction of gross Member energy and demand needs.

Energy efficiency estimates are compiled from multiple sources; annual Colorado energy efficiency estimates are calculated consistent with the 2020 ERP Phase I Settlement Agreement,[3] with estimates derived as the target percentage by year multiplied by annual Colorado gross load net of partial requirements. These annual targets are shaped based on the weighted average of the aggressive incentive level of hourly program profiles provided by a third-party consultant for the Colorado load area. Annual energy efficiency potential for Wyoming and New Mexico, as well as hourly and monthly profiles for each planning region, are developed by compiling the individual measure and program hourly profiles into an hourly shape for each area and incentive level. Wyoming and New Mexico energy efficiency are not part of the native load, but rather a supply side resource option for the expansion model to select.

Energy efficiency estimates are a reduction of gross Member load in the calculation of load served by Tri-State. In contrast, beneficial electrification estimates, which are also calculated by a third-party consultant, are added to gross member load. These are layered onto the gross Member load estimates in Hyperion financial modeling.

Additional details on energy efficiency and beneficial electrification modeling assumptions can be found in Attachments B and G-3 of the ERP Report (LKT-1).

[3] Section 3.11.9.

## Range of Forecasts

This subsection addresses forecast requirements in Commission Rule 3605(b)(II). Tri-State developed a base forecast, as well as two forecast variations, including a low load and high load forecast. To develop the low load and high load forecasts, Tri-State established prediction intervals to express uncertainty around the expected value forecast. The total variance includes both economic and weather-related uncertainty. The low and high load intervals are generated at the 90% confidence interval, meaning that the actual value should be within the given interval with a probability of 90%.

Tri-State did not model resource planning scenarios related to the upper and lower 90% confidence intervals for the purpose of this Resource Plan. However, both the High Load forecast and Low Load forecast are presented in the following subsection, as well as in Attachment F-1 of the ERP Report (LKT-1).

## Base Load Forecast

The gross Base Case load forecast of annual energy, and Tri-State summer and winter coincident peak (TCP) demand is shown, by year of the RPP, in Table 1 below, in compliance with Commission Rule 3605(b)(I)(A). Please note that the base forecast for this, and for all load data presented below and in Attachment F-1 (unless otherwise specified), is gross load, meaning it is gross of Partial Requirements, distributed generation, energy efficiency, beneficial electrification, demand response, member self-generation, and transmission losses. Partial Requirements load assumptions are provided in Table 2 below. Load for the three Utility Member Systems that have provided Tri-State with notice of their intent to depart the system has been excluded as of the noticed departure date.[4] Of note, Tri-State's winter peak is forecasted to shift to January in 2024 due to expected member departures; in all other years of the forecast, the winter peak occurs in December.

*Table 1: Tri-State Gross Annual Energy, Summer Coincident Peak, and Winter Coincident Peak*[5]

| Year | Energy (MWh) | Summer Peak (MW) | Winter Peak (MW) |
|---|---|---|---|
| 2024 | 14,325,075 | 2,419 | 2,230 |
| 2025 | 13,016,605 | 2,381 | 1,761 |
| 2026 | 13,027,503 | 2,403 | 1,779 |
| 2027 | 13,161,110 | 2,423 | 1,800 |
| 2028 | 13,310,698 | 2,448 | 1,807 |
| 2029 | 13,437,397 | 2,466 | 1,825 |
| 2030 | 13,578,717 | 2,489 | 1,845 |
| 2031 | 13,720,347 | 2,511 | 1,867 |
| 2032 | 13,875,367 | 2,536 | 1,887 |
| 2033 | 14,002,551 | 2,554 | 1,906 |
| 2034 | 14,149,447 | 2,578 | 1,927 |

[4] United Power and NRPPD departures are May 1, 2024; Mountain Parks' departure is January 15, 2025.

[5] The energy and demand shown in the tables reflects the sum of member gross energy needs and excludes aggregates that were layered on top of the load forecast, including energy efficiency, beneficial electrification, and partial requirements.

| | | | |
|---|---|---|---|
| 2035 | 14,300,790 | 2,601 | 1,950 |
| 2036 | 14,468,551 | 2,628 | 1,973 |
| 2037 | 14,613,014 | 2,649 | 1,994 |
| 2038 | 14,771,813 | 2,674 | 2,017 |
| 2039 | 14,932,199 | 2,698 | 2,041 |
| 2040 | 15,101,613 | 2,725 | 2,064 |
| 2041 | 15,247,115 | 2,746 | 2,085 |
| 2042 | 15,405,534 | 2,770 | 2,108 |
| 2043 | 15,571,769 | 2,796 | 2,133 |



Table 3 details the relative share of Tri-State load forecasted in each state.

*Table 3: Percentage of Tri-State Load by State, 2025 and 2030*

| | Colorado | New Mexico | Wyoming | Nebraska |
|---|---|---|---|---|
| 2025 | 61% | 19% | 14% | 7% |
| 2030 | 62% | 18% | 14% | 6% |

Table 4 shows a comparison of base total member energy requirements forecast and the load that Tri-State expects to provide (before transmission losses). Of note, the share of energy provided by Tri-State to Members decreases starting in 2026 due to increased energy self-supplied by Members through partial requirements.



[6] Variance reflects adjustments including partial requirements and Member distributed generation. The variance between Member gross load and load served by Tri-State increases in magnitude starting in 2026 due to the expected start of partial requirements.

[redacted]

Table 5 reflects the difference of gross and net peak demand for select years throughout the RPP.

[redacted]

## High Load Forecast

A number of factors exist which could significantly increase Tri-State's load above the base forecast. This includes:

- Delay in the departure of Utility System Members that have submitted exit notices to Tri-State or their inability to fully exit Tri-State.
- Delay of members to reduce their load from Partial Requirements, due to delay in regulatory approvals or supply chain issues. In the 2023 ERP Phase I modeling, all Partial Requirements load reductions are anticipated to start as of January 1, 2026.
- Increased demand resulting from higher than expected economic or population growth (including increased migration to the Tri-State service territory).
- Increased beneficial electrification, including faster than expected adoption of electric vehicles due to government incentives.

## Low Load Forecast

Potential factors exist which could significantly reduce Tri-State's load, including:

- Increased Utility Member distributed generation beyond forecasted amounts due to trend and to Members taking advantage of IRA project funding.
- Higher than forecasted energy efficiency and demand-side management.
- Reduced demand stemming from increased inflation or economic downturns, and
- Load loss related to environmental and regulatory impacts from extractive industries, including natural gas, oil, and coal.

[7] For simplicity, we are showing Tri-State peak demand net of both MAX and MARS partial requirements. Expected impact of Member self-generation under policies 115 and 119 are small. MARS partial requirements is reflected at 5% ELCC.

## Utility Member Sales Forecasts

This subsection addresses forecast requirements in Commission Rule 3650(b)(I)(A). The following graphs show Tri-State's load forecasts for the RPP for the Tri-State System. Tri-State's annual system gross energy average growth from 2024-2043 is 0.44%, while gross summer coincident system demand has an annual average growth rate of 0.76%. Where appropriate, data is presented for a range of forecasts, including Base, High and Low Load forecasts.

### Tri-State System Annual Energy Sales, Summer Peak & Winter Peak

The below graphs detail base, high load, and low load gross system annual energy sales, summer peak, and winter peak for the Resource Planning Period by year.

*Figure 1: Tri-State System Annual Energy Sales to Utility Member Systems*

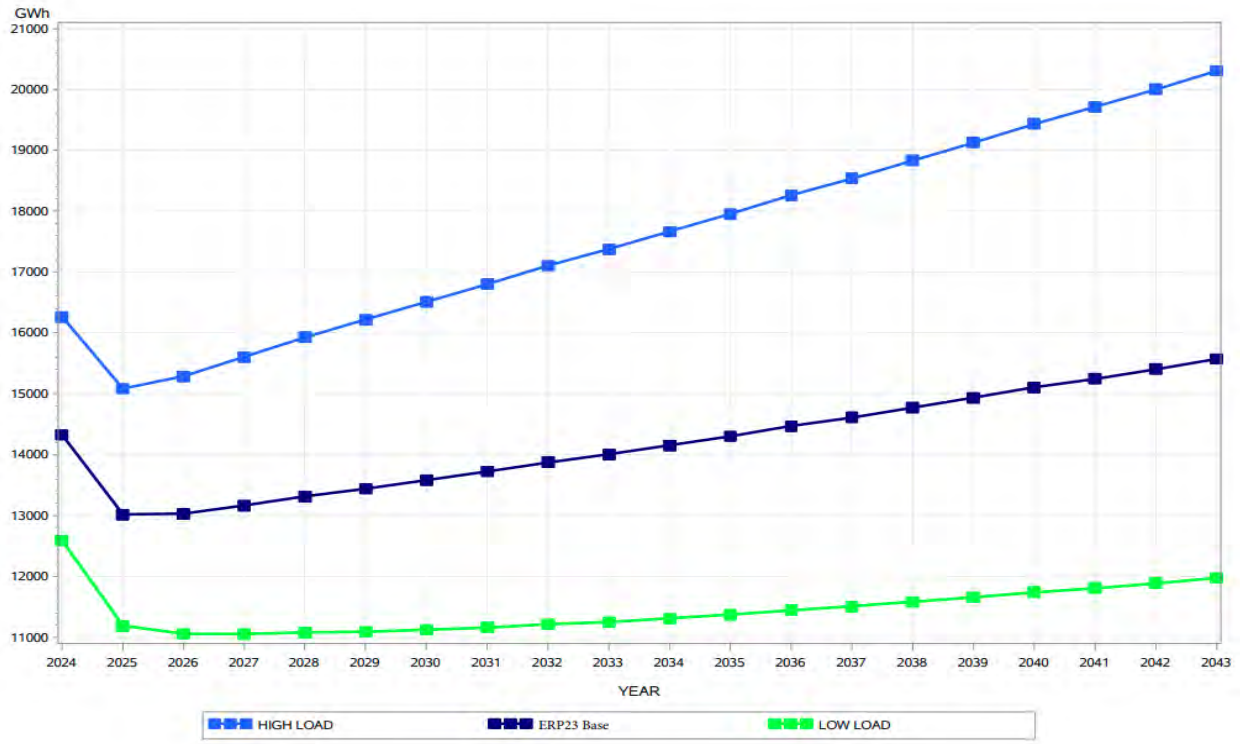


*Figure 2: Tri-State System Annual Coincident Summer Peak*

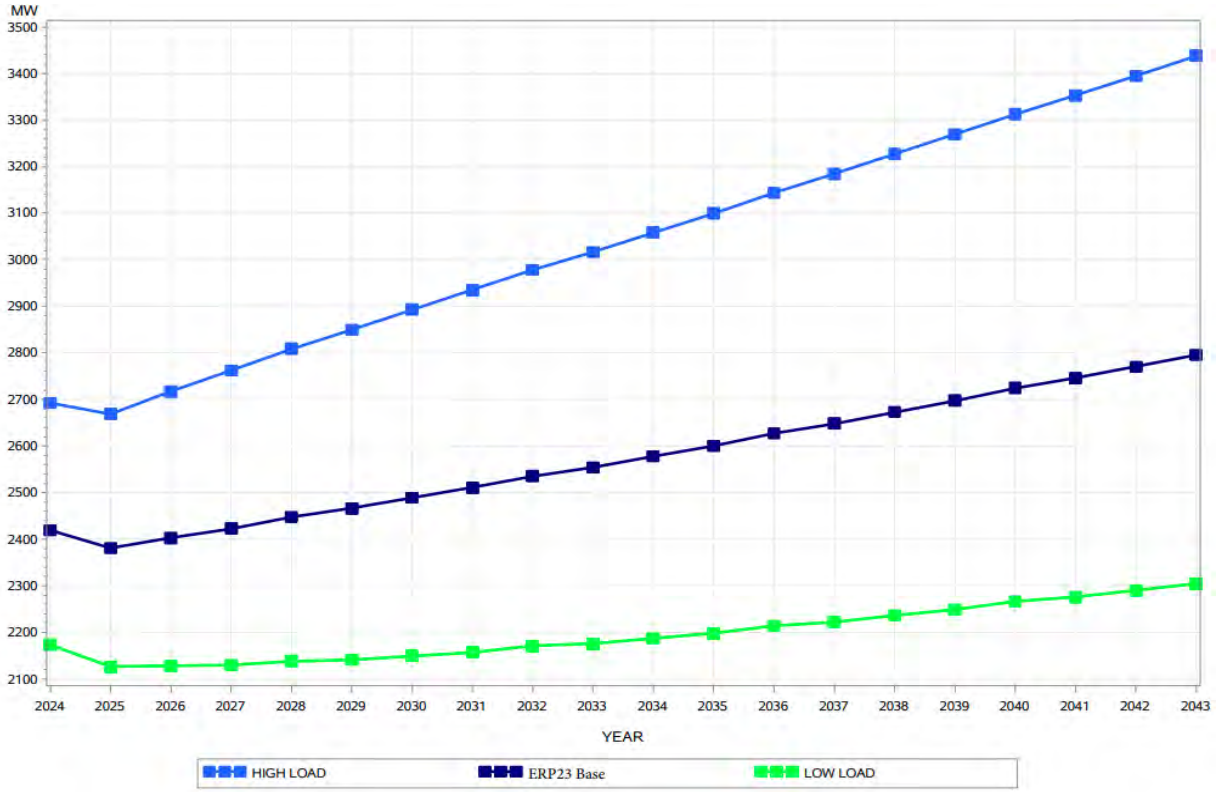
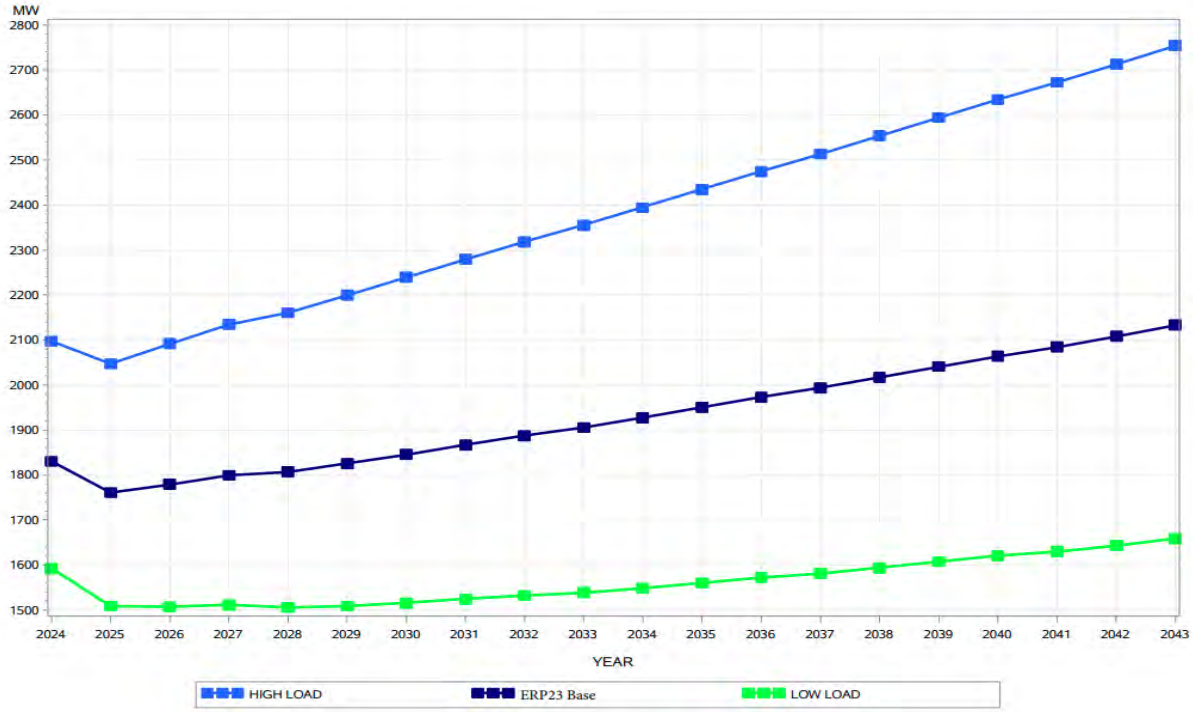



*Figure 3: Tri-State System Annual Coincident Winter Peak*



Additional graphs showing gross energy sales, winter peak, summer peak, and daily profiles for Tri-State, State, and Utility Member Systems can be found in Attachment F-1 of the ERP Report (LKT-1). Table 6 references the page in the attachment that corresponds to the compliance requirement.

*Table 6: Reference Guide for Attachment F-1, Load Graphs by Member and State*

| Rule | Item | Granularity | Page(s) |
|---|---|---|---|
| 3605(b)(I)(A) | Annual Energy Sales | States | 1 |
| 3605(b)(I)(A) | Annual Energy Sales | Utility Member System | 5 |
| 3605(b)(I)(A) | Annual Coincident Summer Peak | States | 47 |
| 3605(b)(I)(A) | Annual Coincident Summer Peak | Utility Member System | 51 |
| 3605(b)(I)(A) | Annual Coincident Winter Peak | States | 93 |
| 3605(b)(I)(A) | Annual Coincident Winter Peak | Utility Member System | 97 |
| 3605(b)(I)(E) | Hourly Peak Day By Calendar Month | States | 139 |
| 3605(b)(I)(E) | Hourly Peak Day By Calendar Month | Utility Member System | 187 |
| 3605(b)(I)(E) | Hourly Off-Peak Day by Calendar Month | States | 656 |
| 3605(b)(I)(E) | Hourly Off-Peak Day by Calendar Month | Utility Member System | 703 |
| 3605(b)(I)(E) | Hourly Average Day by Calendar Month | States | 1171 |
| 3605(b)(I)(E) | Hourly Average Day by Calendar Month | Utility Member System | 1219 |

## Comparison of 2020 ERP Phase II to 2023 ERP Phase I Load Forecast[8]

The gross base load forecast—which is the sum of individual gross load member forecasts in the 2023 ERP Phase I—was produced in summer 2022 and is the same vintage of annual estimate that was used in the 2020 ERP Phase II due to timing of the long-term load forecasting cycle and a short time span between modeling for both ERPs. While the underlying estimates are the same for most members, the 2023 ERP base load forecast is lower due to the removal of load for members expected to depart in 2024 and 2025, as detailed above. The reduction in gross member energy attributed to member departures ranges from 2,288 GWh (14%) in 2024 to 5,254 GWh (26%) in 2040[9] compared to 2020 ERP Phase II. The expected reduction in Tri-State's gross system peak resulting from expected member departures ranges from 646 MW in 2024 (21%) to 966 MW in 2040 (26%). Graphs of the 2020 ERP Phase II (with upper and lower confidence intervals) and the 2023 ERP Phase I gross member load, summer, and winter coincident peaks are shown below.

[8] Rule 3605(b)(III).
[9] 2040 values are shown as 2040 was the final year modeled in the 2020 ERP Phase II.

*Figure 4: Tri-State System Annual Energy Sales to Utility Member Systems*

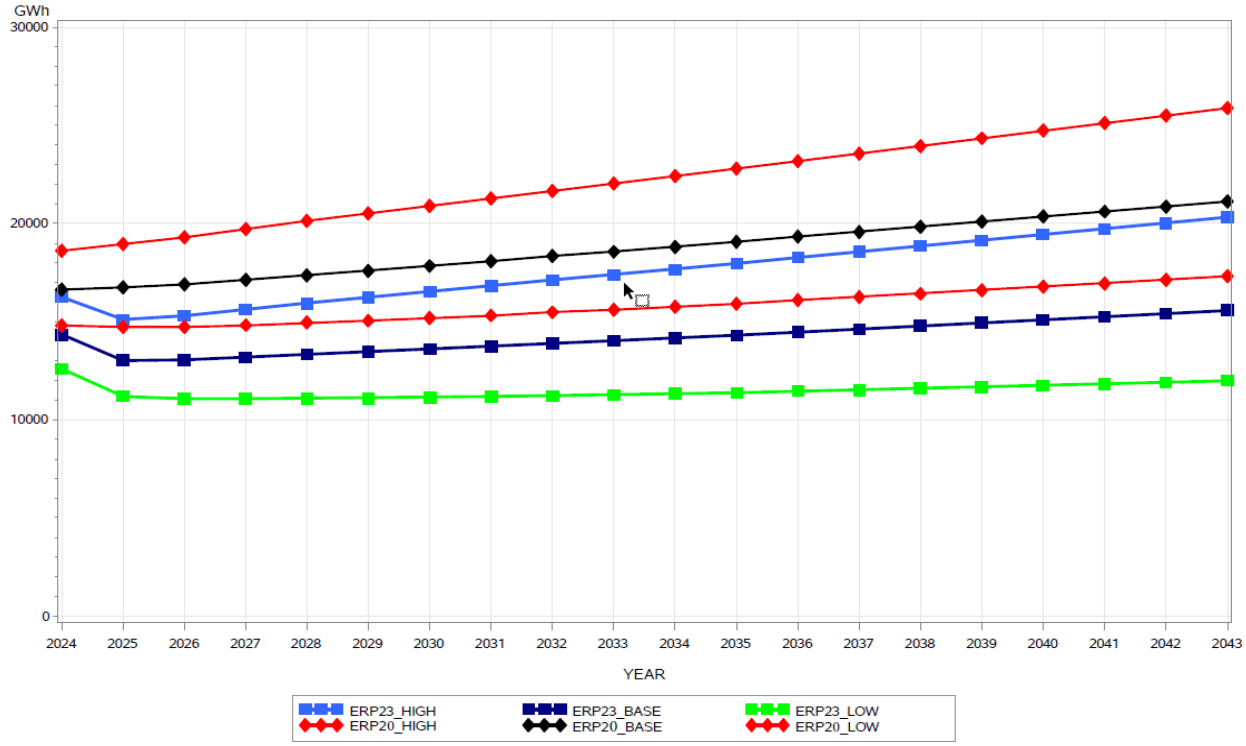



*Figure 5: Tri-State System Annual Summer Coincident Peak*

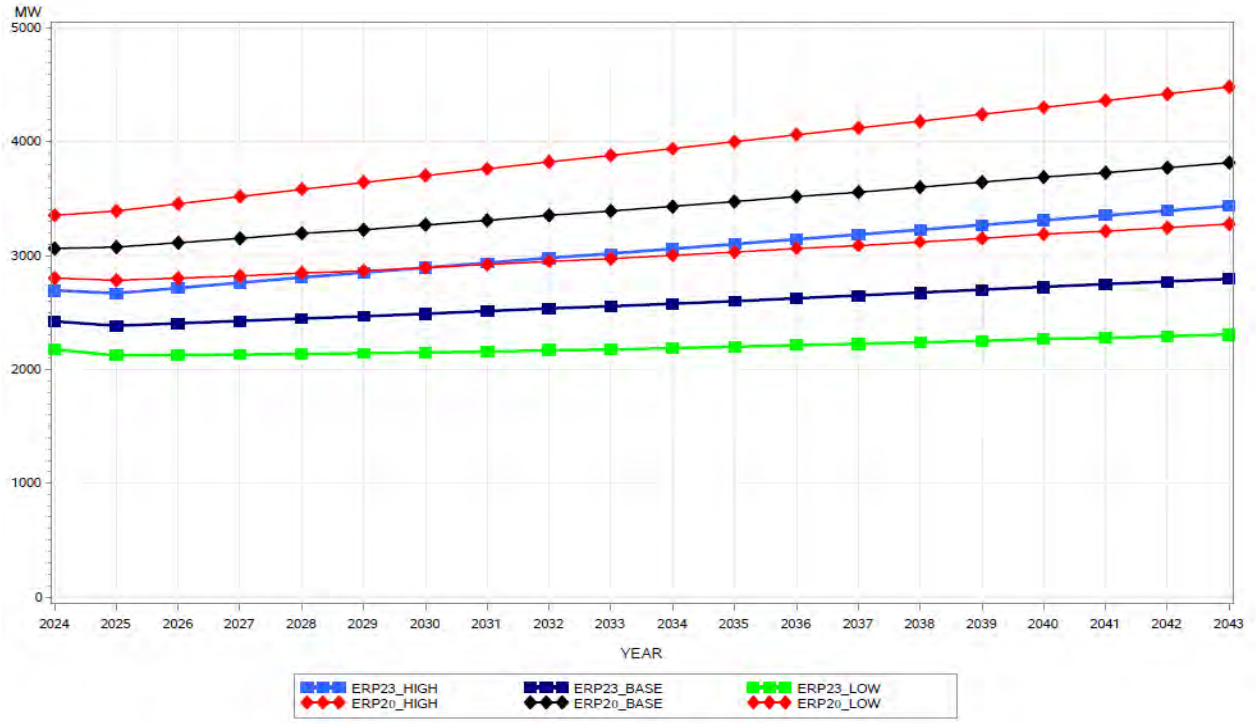
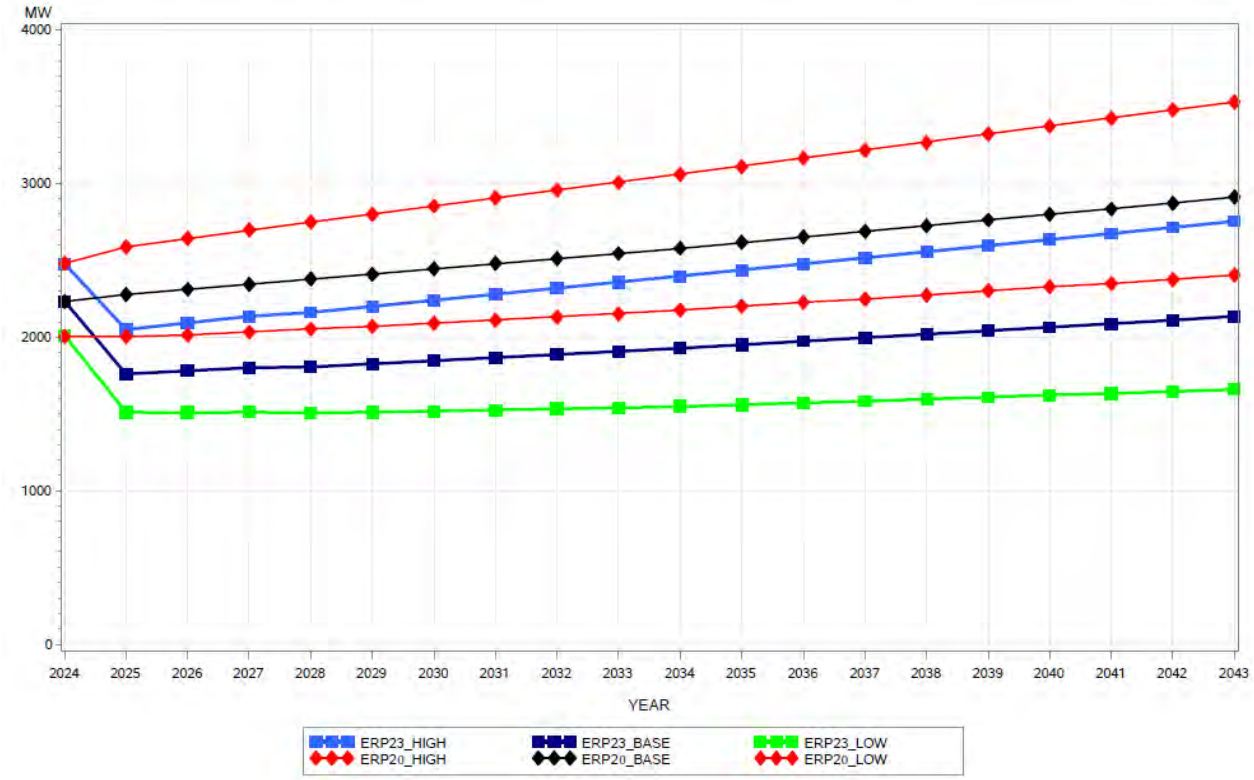


*Figure 6: Tri-State System Annual Winter Coincident Peak*




When comparing the 2023 ERP Phase I load that Tri-State is expecting to serve (inclusive of adjustments) to the 2020 ERP Phase II load, Tri-State made additional adjustments, as noted above. These include the delay of partial requirements to 2026, addition of beneficial electrification, change in energy efficiency targets as a result of member exits, and changes to member-supplied energy contracts, such as community solar. In the 2020 ERP Phase II, Tri-State modeled 300 MW of Partial requirements, with 233 MW starting as of January 1, 2024 and the remaining 67 MW beginning on January 1, 2025. Table 7 below shows the changes and the variance as a percent of 2020 ERP Phase II expected load deliveries for select years.



## Comparison of Historical Forecasts & Actuals

Tables 8 through 10 show the energy sales, summer peak, and winter peak for the prior five years of actuals as well as the annual forecasts in the most recently filed resource plan to the annual forecasts in the current resource plan, in accordance with Commission Rule 3605 (b)(III).

*Table 8: Tri-State System Annual Energy Sales to Utility Member Systems (GWh)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | ACTUALS | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 |
| 2018 | 16,179 | . | . | . | . | . | . |
| 2019 | 16,203 | . | . | . | . | . | . |
| 2020 | 15,983 | . | . | . | . | . | . |
| 2021 | 16,037 | . | . | . | . | . | . |
| 2022 | 16,872 | . | . | . | . | . | . |
| 2023 | . | 16,370 | 16,370 | 18,059 | 18,108 | 14,809 | 14,776 |
| 2024 | . | 16,613 | 14,325 | 18,610 | 16,259 | 14,792 | 12,586 |
| 2025 | . | 16,733 | 13,017 | 18,956 | 15,084 | 14,727 | 11,190 |
| 2026 | . | 16,879 | 13,028 | 19,292 | 15,285 | 14,722 | 11,058 |
| 2027 | . | 17,110 | 13,161 | 19,701 | 15,604 | 14,812 | 11,053 |
| 2028 | . | 17,360 | 13,311 | 20,118 | 15,927 | 14,933 | 11,076 |
| 2029 | . | 17,583 | 13,437 | 20,494 | 16,214 | 15,041 | 11,089 |
| 2030 | . | 17,824 | 13,579 | 20,882 | 16,511 | 15,171 | 11,122 |
| 2031 | . | 18,065 | 13,720 | 21,265 | 16,802 | 15,308 | 11,161 |
| 2032 | . | 18,323 | 13,875 | 21,662 | 17,106 | 15,463 | 11,216 |
| 2033 | . | 18,547 | 14,003 | 22,018 | 17,372 | 15,593 | 11,251 |
| 2034 | . | 18,794 | 14,149 | 22,397 | 17,659 | 15,746 | 11,306 |
| 2035 | . | 19,046 | 14,301 | 22,780 | 17,950 | 15,905 | 11,368 |
| 2036 | . | 19,318 | 14,469 | 23,184 | 18,258 | 16,083 | 11,445 |
| 2037 | . | 19,561 | 14,613 | 23,554 | 18,537 | 16,239 | 11,505 |
| 2038 | . | 19,821 | 14,772 | 23,942 | 18,832 | 16,411 | 11,579 |
| 2039 | . | 20,083 | 14,932 | 24,332 | 19,128 | 16,585 | 11,656 |
| 2040 | . | 20,356 | 15,102 | 24,733 | 19,434 | 16,770 | 11,741 |
| 2041 | . | 20,600 | 15,247 | 25,100 | 19,710 | 16,932 | 11,808 |
| 2042 | . | 20,859 | 15,406 | 25,484 | 20,002 | 17,108 | 11,887 |
| 2043 | . | 21,128 | 15,572 | 25,880 | 20,303 | 17,292 | 11,973 |

*Table 9: Tri-State System Annual Summer Coincident Peak (MW)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | ACTUALS | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 |
| 2018 | 2,887 | . | . | . | . | . | . |
| 2019 | 2,922 | . | . | . | . | . | . |
| 2020 | 2,896 | . | . | . | . | . | . |
| 2021 | 2,975 | . | . | . | . | . | . |
| 2022 | 3,070 | . | . | . | . | . | . |
| 2023 | . | 3,023 | 3,023 | 3,269 | 3,274 | 2,796 | 2,793 |
| 2024 | . | 3,065 | 2,419 | 3,352 | 2,693 | 2,803 | 2,173 |
| 2025 | . | 3,073 | 2,381 | 3,393 | 2,669 | 2,785 | 2,126 |
| 2026 | . | 3,113 | 2,403 | 3,458 | 2,718 | 2,804 | 2,128 |
| 2027 | . | 3,151 | 2,423 | 3,521 | 2,762 | 2,823 | 2,130 |
| 2028 | . | 3,194 | 2,448 | 3,585 | 2,809 | 2,849 | 2,139 |
| 2029 | . | 3,230 | 2,466 | 3,643 | 2,850 | 2,868 | 2,141 |
| 2030 | . | 3,271 | 2,489 | 3,704 | 2,893 | 2,894 | 2,150 |
| 2031 | . | 3,310 | 2,511 | 3,763 | 2,935 | 2,920 | 2,157 |
| 2032 | . | 3,355 | 2,536 | 3,825 | 2,978 | 2,951 | 2,171 |
| 2033 | . | 3,390 | 2,554 | 3,880 | 3,017 | 2,972 | 2,176 |
| 2034 | . | 3,433 | 2,578 | 3,941 | 3,059 | 3,002 | 2,187 |
| 2035 | . | 3,473 | 2,601 | 4,000 | 3,100 | 3,030 | 2,198 |
| 2036 | . | 3,520 | 2,628 | 4,062 | 3,144 | 3,065 | 2,214 |
| 2037 | . | 3,559 | 2,649 | 4,120 | 3,184 | 3,090 | 2,223 |
| 2038 | . | 3,602 | 2,674 | 4,181 | 3,227 | 3,122 | 2,237 |
| 2039 | . | 3,645 | 2,698 | 4,241 | 3,270 | 3,153 | 2,249 |
| 2040 | . | 3,691 | 2,725 | 4,303 | 3,313 | 3,188 | 2,267 |
| 2041 | . | 3,730 | 2,746 | 4,360 | 3,353 | 3,214 | 2,276 |
| 2042 | . | 3,773 | 2,770 | 4,420 | 3,395 | 3,246 | 2,290 |
| 2043 | . | 3,817 | 2,796 | 4,482 | 3,438 | 3,278 | 2,304 |

*Table 10: Tri-State System Annual Winter Coincident Peak (MW)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | ACTUALS | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 | ERP 2020 PHASE II | ERP 2023 |
| 2018 | 2,233 | . | . | . | . | . | . |
| 2019 | 2,199 | . | . | . | . | . | . |
| 2020 | 2,106 | . | . | . | . | . | . |
| 2021 | 2,120 | . | . | . | . | . | . |
| 2022 | 2,322 | . | . | . | . | . | . |
| 2023 | . | 2,245 | 2,231 | 2,491 | 2,475 | 2,019 | 2,009 |
| 2024 | . | 2,276 | 2,230 | 2,556 | 2,098 | 2,021 | 1,592 |
| 2025 | . | 2,279 | 1,761 | 2,586 | 2,047 | 2,003 | 1,509 |
| 2026 | . | 2,310 | 1,779 | 2,641 | 2,092 | 2,015 | 1,507 |
| 2027 | . | 2,344 | 1,800 | 2,696 | 2,135 | 2,031 | 1,511 |
| 2028 | . | 2,378 | 1,807 | 2,750 | 2,161 | 2,051 | 1,506 |
| 2029 | . | 2,409 | 1,825 | 2,801 | 2,200 | 2,067 | 1,509 |
| 2030 | . | 2,443 | 1,845 | 2,853 | 2,240 | 2,087 | 1,515 |
| 2031 | . | 2,478 | 1,867 | 2,905 | 2,279 | 2,110 | 1,525 |
| 2032 | . | 2,512 | 1,887 | 2,956 | 2,318 | 2,132 | 1,533 |
| 2033 | . | 2,544 | 1,906 | 3,006 | 2,355 | 2,151 | 1,539 |
| 2034 | . | 2,579 | 1,927 | 3,057 | 2,394 | 2,174 | 1,548 |
| 2035 | . | 2,616 | 1,950 | 3,110 | 2,434 | 2,200 | 1,561 |
| 2036 | . | 2,653 | 1,973 | 3,163 | 2,475 | 2,225 | 1,572 |
| 2037 | . | 2,687 | 1,994 | 3,215 | 2,513 | 2,247 | 1,581 |
| 2038 | . | 2,724 | 2,017 | 3,268 | 2,554 | 2,273 | 1,594 |
| 2039 | . | 2,762 | 2,041 | 3,321 | 2,594 | 2,300 | 1,608 |
| 2040 | . | 2,799 | 2,064 | 3,374 | 2,634 | 2,326 | 1,620 |
| 2041 | . | 2,833 | 2,085 | 3,425 | 2,673 | 2,349 | 1,630 |
| 2042 | . | 2,870 | 2,108 | 3,478 | 2,713 | 2,376 | 1,643 |
| 2043 | . | 2,910 | 2,133 | 3,532 | 2,755 | 2,405 | 1,659 |

## Other Load Aggregates and Impacts

### Losses[10]

Tri-State adds a 3.5% transmission loss factor to load across Tri-State's system in the Western Interconnection, excluding in the PNM BA area[11], for modeling purposes. Tri-State load in the Western Interconnection is located in multiple BA and TP systems. The 3.5% transmission loss factor is meant to represent an average of expected transmission losses. Tri-State's load in the Eastern Interconnection is covered by a full requirements contract.

[10] Rule 3605(b)(I)(D).
[11] Losses in PNM BA are handled financially and included in the financial forecast.

## Energy and Capacity Sales to Other Utilities[12]

Annual contract energy and capacity sales to other utilities and counterparties are described in Attachment B of the ERP Report (LKT-1), as well as modeled proxy sales in anticipation of the ability to sell excess power upon Member exits.

## Intra-Utility Energy and Capacity Use[13]

Tri-State intra-utility loads consist of a number of service centers and the headquarters building. For these loads, Tri-State takes retail service from the local provider. Accordingly, Tri-State has no intra-utility loads that contribute to energy and capacity requirements for purposes of Tri-State resource planning.

## Potential Benefits of Strategically Locating Distributed Energy Storage within Member Cooperative Territories

Tri-State allows for distributed energy storage projects through Tri-State Board Policy 115. Members elect whether or not to pursue Policy 115 projects, including determination of technology type, project size (within policy limitations), and project location. Tri-State works with interested Members to develop programs that are beneficial, while minimizing program impacts to all Members.

[12] Rule 3605(b)(I)(B).
[13] Rule 3605(b)(I)(C).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit DD: CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E

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**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**

**PROCEEDING NO. 23A-____E**

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**IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN**

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# DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN L. THOMPSON ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

**December 1, 2023**

Colorado PUC E-Filings System

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# ATTACHMENTS

| | |
|---|---|
| BLT-1 | Statement of Qualifications for Brian L. Thompson |

## I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Brian Thompson. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

**Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Resource Planning Manager.

**Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?**

A: I am testifying on behalf of Tri-State.

**Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?**

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment BLT-1**.

**Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.**

A: I have 16 years of experience in the electric utility industry. I manage the resource planning group at Tri-State. We are responsible for short-term and long-term modeling of the Tri-State system, including scenario and portfolio modeling associated with the ERP/IRP process. Previously, I held the following positions at Tri-State: Associate Real Time Marketer, Senior Energy Portfolio Analyst, Term Marketer, and Senior Engineer Resource Planning. I have a Bachelor of Science in Manufacturing Engineering Technology from Brigham Young University.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A: My testimony addresses the 2023 Electric Resource Plan ("ERP") model set-up based on the Tri-State system topology and key data input assumptions for Tri-State's Phase I ERP, including generic resource parameters, as well as summarizes third-party study results.

**Q: ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR DIRECT TESTIMONY?**

A: Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BLT-1: Statement of Qualifications for Brian L. Thompson

## II. TRI-STATE'S APPROACH TO MODELING

**Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A: In this section of my Direct Testimony, I describe the systems and analytical methodologies utilized by Tri-State to develop its 2023 ERP, including the modeling software used for expansion plan and dispatch modeling.

**Q: WHAT MODELING TOOL IS BEING USED IN THE 2023 ERP?**

A: Tri-State is continuing to use EnCompass software for the 2023 ERP, which was also utilized for Phase II of the 2020 ERP.

**Q: PLEASE DESCRIBE THE SYSTEMS AND ANALYTICAL METHODOLOGIES EMPLOYED TO DEVELOP THE 2023 ERP.**

A: The ERP Report (**Attachment LKT-1**) describes the systems Tri-State utilized for modeling the 2023 ERP and it also identifies the flow of input and output data between each system. As stated above, Tri-State utilizes EnCompass software for the expansion plan and dispatch modeling, as was done for Phase II of the

2020 ERP. The modeling setup is reflective of Tri-State's four-state system and location of our generation, load pockets, markets, transmission availability and constraints, and power flows between regions (visually represented in **Attachment** LKT-13 ~~**B-6** of the ERP Report (**Attachment LKT-1**)~~. The system topology is largely similar to what was modeled in Phase II of the 2020 ERP, with three updates:

- Assumed energy transfer capability from the Eastern Colorado ("ECO") to New Mexico ("NM") planning regions was modified from 200 MW to 191 MW.
- 100 MW of energy transfer capability, at an incremental cost of $8.06/MWh, was added from the NM to the ECO planning region.
- 76 MW of energy transfer capacity, at an incremental cost of $2.39/MWh, was added from the ECO to Western Colorado ("WCO") planning region.

In addition to the base modeling set-up to reflect the Tri-State system, numerous financial, operational, and environmental data assumptions are input into the model. Once the topography design and all input assumptions are input and tested in EnCompass, scenario modeling can begin.

**Q: PLEASE PROVIDE AN OVERVIEW OF TRI-STATE'S RESOURCE PLAN SCENARIO MODELING PROCESS.**

A: Tri-State models several resource plan scenarios. Each scenario is grounded in the base modeling assumptions, but with unique modeling assumptions applied as identified in **Attachment** LKT-10 ~~**B-3** of the ERP Report (**LKT-1**)~~. In the first step, the model output results in an optimal expansion plan, which includes selected new generation needs, selected unit retirements, and levels of demand-side

management. In the second step, the model dispatches the generation to meet load across the planning period based on the given expansion plan, existing resources, and system constraints. The 8760 dispatch run results in modeling outputs such as forecasted unit capacity factors, market sales and purchases, energy required, curtailments, unit starts, heat required, fuel costs, and transmission flows. The expansion plan and dispatch outputs are analyzed by Tri-State's financial and transmission planning teams to assess the forecasted financial impact of the generation and transmission requirements of each scenario.

**Q: HOW MANY SCENARIOS DID TRI-STATE MODEL?**

A: Tri-State modeled five scenarios. Each scenario reflected the base modeling assumptions, but with alterations to the assumptions based on Tri-State and stakeholders' desired parameters. The modeling of each scenario results in a unique expansion plan, dispatch, and financial result for each scenario. Following the completion of each scenario modeling run, the scenarios were tested and analyzed to evaluate their performance under two sensitivity conditions. A sensitivity analysis maintains the same expansion plan (i.e., generation units available to meet load in a given year) but modifies assumptions about the system operational environment (e.g., weather, prices) to test the performance of a scenario under potential hardship circumstances that could arise. I discuss the details of modeling sensitivities further below.

**Q: WHAT ARE SOME OF THE PRIMARY DATA INPUTS FOR SCENARIO MODELING?**

A: Data inputs fall into three core categories: 1) operational/technical, 2) financial, and

3) environmental. Some of the primary data inputs for scenario modeling include:

- Operational/Technical: load forecast, transmission constraints, outage rates, Electric Load Carrying Capability ("ELCC"), contracts, operational data related all resources, demand-side management and beneficial electrification potential, etc.
- Financial: capital expenditure forecast, operations and maintenance ("O&M") forecast, generic resource pricing, forward pricing of power and gas curves, etc.
- Environmental: carbon emission limits.

These are a sampling of the numerous data inputs that are included in the model. A list of all modeling assumptions can be found in **Attachment ~~B~~** ~~of the ERP Report (**LKT-1**).~~ LKT-7

**Q: PLEASE IDENTIFY THE MOST SIGNIFICANT UPDATES TO MODELING INPUT ASSUMPTIONS FOR THE 2023 ERP.**

A: Tri-State reviews all of the operational, financial, and environmental data inputs to assess the need for updates or modification based on current operating conditions and policy requirements. The significant modeling modifications of note include:

- Planning Reserve Margin ("PRM") adjustment, starting at 22% and transitioning to 30.5% after Craig 3 retires;
- Updated ELCC values for wind, solar, and storage, and capacity credit for thermal units;
- Updated load forecast that removes exiting Members' loads and loads to be

served through Partial Requirements;

- Numerous updated financial assumptions, such as decommission cost, generic resource pricing, fixed and variable O&M costs, and the forecast of capital expenditures; and
- Inclusion of several new innovative technologies not previously modeled by Tri-State for the model to evaluate.

**Q: WHAT OUTPUTS RESULT FROM THE ERP MODELING FOR EACH SCENARIO?**

A: Through the modeling, we are able to forecast our resource mix, new resource additions, financial and environmental impacts, and the level of reliability achieved by each scenario, among other outputs. The modeling results for each scenario are shown in the ERP Report (**LKT-1**).

## III. STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING

**Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A: In this section of my Direct Testimony, I provide a description of the third-party studies and analyses supporting the 2023 ERP Phase I.

**Q: PLEASE PROVIDE AN OVERVIEW OF THE STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING.**

A: There were four studies completed to inform Tri-State's 2023 ERP modeling, these include:

- Benchmarking Analysis: This study was completed by Black & Veatch in October 2023. It compares existing resources and generic resources, in regard to cost and performance. This study is provided as **Attachment G-**

LKT-30

~~**2** of the ERP Report (**LKT-1**).~~

- ELCC and PRM Study: Tri-State engaged Astrape to perform an ELCC Study for establishing ELCCs for solar, wind, and storage at various penetration levels, and capacity credits for thermal resources, as well as for establishing an appropriate PRM. This study was completed in August 2023 and is provided as **Attachment** LKT-29 ~~**G-1** of the ERP Report (**LKT-1**).~~
- IRA Scenario Reliability Evaluation: Astrape performed a supplemental analysis of the IRA Scenario's reliability in year 2032 of the planning period. This analysis is provided as **Attachment** LKT-32 ~~**G-4** of the ERP Report (**LKT-1**).~~
- DSM Potential Study and BE Potential Study: Mesa Point updated the 2020 Potential Studies in May 2023 to refresh the level of Demand-Side Management ("DSM") energy savings and beneficial electrification ("BE") potential within the Tri-System resulting from the exit of three Members from the system, updated equipment use and saturations, as well as updated avoided costs, emissions rates, and social cost of carbon. This study is provided as **Attachment** LKT-31 ~~**G-3** of the ERP Report (**LKT-1**).~~

**a. Benchmarking Analysis**

**Q: PLEASE DESCRIBE THE BENCHMARKING ANALYSIS.**

A: Tri-State engaged Black & Veatch ("B&V") to perform an analysis of cost and performance of existing owned resources, contracted resources, and generic resources. The study provides a resource ranking for each existing and generic resource, with and without sunk costs. Key insights from the B&V's Benchmarking Analysis include:

- On a Levelized Cost of Energy ("LCOE") basis, wind and solar PPAs and build-transfers, and pumped storage resources are the lowest cost;[1] and
- On a Levelized Cost of Capacity ("LCOC") basis, simple cycle combustion turbine resources are the lowest cost.[2]

Not surprisingly, the study acknowledges that sunk costs (depreciation, decommissioning, etc.) are a significant driver in the cost-effectiveness of Tri-State owned resources.[3]

**Q: HOW DO THE RESULTS OF THE BENCHMARKING ANALYSIS INFORM TRI-STATE'S ERP APPLICATION?**

A: The Benchmarking Analysis identifies the levelized cost of each resource in Tri-State's fleet, as well as the levelized cost of potential new generic resources to be added to our fleet and identifies how they perform in comparison to one another. These results offer the opportunity for Tri-State to assess which units are out-performing others, based on certain factors. While the benchmarking results are informative, resource plan modeling is able to take into consideration a number of key assumptions, including environmental and transmission constraints which ensures a comprehensive approach to resource planning analysis.

**b. <u>ELCC and PRM Study</u>**

**Q: PLEASE DESCRIBE THE ELCC COMPONENT OF THE ASTRAPE STUDY.**

A: The Astrape study determines the appropriate ELCCs for solar, wind and battery

[1] **Attachment ~~G-2~~,** pg. 10. LKT-30
[2] **Attachment ~~G-2~~,** pg. 11. LKT-30
[3] **Attachment ~~G-2~~,** pg. 12. LKT-30

storage resources on the Tri-State system given an anticipated resource mix, and capacity credits for thermal units. Applying appropriate ELCCs, represented as a percent of nameplate capacity, enables calculation of the amount of dependable capacity that can be counted on by the system for resource adequacy purposes. The primary result of ELCC Study is a three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any level of penetration of solar, wind, and batteries. Astrape provided Tri-State ELCCs for Tri-State's anticipated resource mix but also provided a tool to enable calculation of the average and marginal ELCCs for a given penetration level of solar, wind, and batteries in each scenario modeled in the event any scenario deviated substantially from the anticipated mix.

**Q: HOW IS THE ELCC METHODOLOGY USED IN TRI-STATE'S PHASE I MODELING?**

A: As resource penetrations increase over time, the technology-specific ELCCs decline. The appropriate ELCC is applied in EnCompass for each existing and new generating unit based on the level of installed capacity of the technology, as shown in **Table BLT-D-1**. The ELCC values result from the Astrape Study.

**Table BLT-D-1. ELCC Values for 2023 ERP Phase I**

| Solar | | Wind | | 4-hour Batteries | |
|---|---|---|---|---|---|
| Levels (MW) | ELCC | Levels (MW) | ELCC | Levels (MW) | ELCC |
| 0 to 820 | 5% | 0 to 790 | 17% | 0 to 100 | 97% |
| 821 to 1200 | 3% | 791 to 1200 | 10% | 101 to 200 | 89% |
| 1201 to 1600 | 3% | 1201 to 1600 | 9% | 201 to 400 | 65% |
| 1601 to 2000 | 1% | 1601 to 2000 | 6% | 401 to 800 | 45% |

**Q: DID TRI-STATE PREVIEW THE ELCC METHODOLOGY AND RESULTS WITH STAKEHOLDERS PRIOR TO PERFORMING SCENARIO MODELING?**

A: Yes. Tri-State committed to hold at least two meetings with interested stakeholders in advance of beginning Phase I modeling to seek input on ELCCs.[4] Ultimately, five discussions were convened on this topic. Tri-State first shared its approach to the ELCC Study during a meeting with stakeholders on January 17, 2023. During that initial meeting, Tri-State indicated its intention to calculate ELCC values based on a deterministic approximation method developed by the National Renewable Energy Laboratory ("NREL"). On February 23, 2023, Tri-State again met with stakeholders to share updates to the ELCC calculations. However, during a meeting on March 14, 2023, stakeholders questioned whether a probabilistic method for determining ELCCs could be used instead of the NREL method. On

[4] 2020 ERP Settlement Agreement, Section 3.11.13.

April 24, 2023, Tri-State met with stakeholders again to discuss two possible paths forward for the ELCC Study: (1) one that would require several months to hire a third-party consultant to complete a probabilistic study for Phase I, and (2) one that would maintain the NREL method for Phase I and update ELCCs using a probabilistic study in advance of Phase II. Stakeholders indicated preference for a probabilistic study to be performed for Phase I. Tri-State met with stakeholders on this topic again on July 19, 2023 to present the results of the probabilistic study completed by Astrape.

**Q: PLEASE DESCRIBE THE ELEMENT OF THE ASTRAPE STUDY RELATING TO PRM.**

A: The study completed by Astrape also calculated a PRM for Phase I of the 2023 ERP. Astrape modeled the system using thousands of simulations varying weather, hourly and peak loads, and unit outages, with the calculated PRM being based on the weighted average results. The result being a PRM of 22 percent, transitioning to 30.5 percent after retirement of Craig Station.[5]

Some of the factors noted by Astrape in their study that influenced the PRM include:

- Impact of "shaft risk," which is the risk associated with the potential loss of units that are large relative to peak load. With Tri-State's load being reduced by approximately one-third due to Member exits and the Craig Station retiring, more risk relative to load is placed on the remaining

[5] **Attachment ~~G-1~~**, pg. 67. LKT-29

dispatchable units.

- The PRM calculation also discounts the capacity of conventional resources by their Equivalent Forced Outage Rate and several of Tri-State's thermal resources have relatively high and increasing forced outage rates.

**c. <u>IRA Scenario Reliability Evaluation</u>**

**Q: PLEASE DESCRIBE THE PURPOSE OF THE IRA SCENARIO RELIABILITY EVALUATION.**

A: Astrape was engaged by Tri-State to conducts an analysis of the IRA Scenario's reliability in 2032.

**Q: WHAT DOES THE EVALUATION SHOW?**

A: The evaluation shows that the IRA Scenario is reliable with a very low LOLE of 0.036 days/year in 2032, providing additional assurance of reliability as a result of this plan.

**d. <u>DSM Potential Study</u>**

**Q: PLEASE DESCRIBE THE DSM POTENTIAL STUDY.**

A: The DSM Potential Study identifies potential energy savings and associated costs for attaining energy savings under varying DSM Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we work closely with our Members to facilitate their DSM program offerings and ease program administration burdens.

**Q: IS OUTPUT FROM THE DSM POTENTIAL STUDY USED TO MODEL THE**

**COLORADO ENERGY EFFICIENCY TARGETS THAT TRI-STATE HAS COMMITTED TO STARTING IN 2023?**

A: No. Tri-State models the 2023, 2024, 2025, and 2030 EE Targets[6] as a "must-take" level of energy savings in the resource planning period ("RPP") in all 2023 ERP Phase I scenarios, for the ECO and WCO planning regions. The EE Targets are identified in **Attachment B** ~~of the ERP Report (**LKT-1**).~~ LKT-7 The 2025 EE Target is held constant from 2025-2029 and the 2030 target is held constant through the remainder of the planning period.

**Q: HOW ARE THE RESULTS OF THE DSM POTENTIAL STUDY USED IN TRI-STATE'S 2023 ERP PHASE I MODELING?**

A: For any ERP scenarios that allows for either deeper levels of energy savings in ECO and WCO, or DSM as a selectable option for the NM or Wyoming/West Nebraska ("WYO/WNE") regions, the DSM Potential Study determines the level of energy savings assumed. Tranches of energy savings opportunity are selectable only based on the DSM Potential Study scenario levels (e.g., Low, Moderate, etc.). The costs to achieve the level of assumed energy savings also reflects input from Tri-State DSM program staff.

**e. <u>BE Potential Study</u>**

**Q: PLEASE DESCRIBE TRI-STATE'S BE POTENTIAL STUDY.**

A: The BE Potential Study identifies potential load growth opportunities from electrification and associated costs for attaining the additional load under varying

[6] 2020 ERP Settlement Agreement, section 3.11.9.

BE Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we do work closely with our members to facilitate their BE program offerings and ease program administration burdens.

**Q: HOW ARE THE RESULTS OF THE BE POTENTIAL STUDY USED IN TRI-STATE'S PHASE I MODELING?**

A: The BE Potential Study determines the level of new load assumed based on study's scenario levels (e.g., Low, Moderate, etc.). For all scenarios in the 2023 ERP Phase I, Tri-State's load forecast is adjusted to reflect inclusion of the Achievement-Moderate level of BE. This approach is pursuant to the 2020 ERP Phase I Unopposed Comprehensive Settlement Agreement in Proceeding No. 20A-0528E ("2020 ERP Settlement Agreement").[7]

**Q: DID TRI-STATE FULFILL ITS COMMITMENT TO HOLD STAKEHOLDER MEETINGS ON BE PRIOR TO MODELING?**

A: Yes. Pursuant to 2020 ERP Phase I Settlement Agreement, Tri-State held two stakeholder meetings on BE best practices in advance of the 2023 ERP modeling, as identified in the ERP Report (**Attachment LKT-1**).

## IV. GENERIC RESOURCE MODELING

**Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A: In this section of my Direct Testimony, I discuss Tri-State's approach to generic

[7] 2020 ERP Settlement Agreement, section 3.11.11.

resources modeled in the ERP**.**

**Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO GENERIC RESOURCES.**

A: New to the 2023 ERP Phase I, Tri-State included several new emerging technologies as generic resource options available for scenario modeling. Tri-State also held meetings with stakeholders, prior to modeling, to share data and assumptions for both new and existing generic resource options.[8] Tri-State also refreshed data and assumptions for the generic resource types that had been modeled in the 2020 ERP.

**Q: HOW ARE GENERIC RESOURCES MODELED IN THE ERP?**

A: In expansion plan modeling in EnCompass, a given scenario results in the selection of a unique set of generic resource types, locations, and target commercial operation dates ("CODs"). The modeling assesses a variety of factors in determining the expansion plan needed to meet Tri-State system load and PRM over the resource planning period. Such factors include, but are not limited to, financial assumptions regarding resource costs, resource operational parameters, and environmental characteristics of the available technologies. The expansion plan output reflects the optimal solution for economically meeting the numerous constraints input into the model, such as transmission and new build constraints (**Attachment B-1, B-2** ~~of the ERP Report (**LKT-1**)),~~ LKT-8 AND LKT-9 emissions reduction targets, and others.[9]

[8] Pursuant to 2020 ERP Settlement Agreement, Section 3.11.15., Tri-State held several meetings with stakeholders to discuss new generic resources (as identified in the ERP Report (**Attachment LKT-1**)) and shared generic resource assumptions with stakeholders in advance of modeling.
[9] 2020 ERP Settlement Agreement 3.3.4. and 3.3.5.

**Q: WHAT NEW TECHNOLOGIES DID TRI-STATE INCLUDE IN ITS GENERIC RESOURCE DATASET?**

A: New technologies modeled in the Phase I 2023 ERP are identified in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**)~~ and include:

- 10-hour Battery Storage
- Molten Salt Long-Term Storage;
- Iron Air Multi-Day Storage;
- Advanced and Enhanced Geothermal;
- Green and Blue Hydrogen;
- Natural Gas Combined Cycle with Carbon Capture and Sequestration ("NGCCS"); and
- Small Modular Reactors ("SMRs").

Key financial, operational, and environmental assumptions about each technology type are included in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**).~~ The sources for this data include third-party experts, technology vendors, and trusted industry research sources such as the National Laboratories. Not all technologies are assumed to be deployment-ready during the first year of the RPP. Additionally, several of the new technologies were not selected in any of the scenario expansion plans.

**Q: HOW DID TRI-STATE CONSIDER THE IMPACT OF FEDERAL FUNDING OPPORTUNITIES IN PRICING GENERIC RESOURCES?**

A: The financial assumptions for the generic resources reflect applicable available

federal tax incentives, including the Investment Tax Credit ("ITC") or Production Tax Credit ("PTC"). The following technology types are assumed to be eligible for a 40 percent ITC:

- battery component of hybrid build-transfer;
- 4- and 10-hr batteries;
- pumped storage;
- advanced geothermal;
- enhanced geothermal baseload;
- enhanced geothermal with 12-hour storage;
- green hydrogen; and
- SMRs.

Molten salt and iron air technologies are assumed to be eligible for a 50 percent ITC, due to the expectation that they could qualify for the domestic content bonus credit.

The following technology types are assumed to be eligible for an energy-production based PTC:

- solar
- wind;
- solar and wind hybrids;
- blue hydrogen; and
- NGCCS.

For both existing and generic resources, that were assumed to be build-

transfer projects owned by Tri-State, it is assumed that Tri-State would be eligible for direct pay of tax credits, as described in the Direct Testimony of Lisa Tiffin.

## V. MARKET DEPTH ASSUMPTIONS

**Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A: In this section of my Direct Testimony, I discuss how Tri-State's planned market participation is reflected in the modeling approach.

**Q: HOW DOES TRI-STATE'S MODELING ACCOUNT FOR TRI-STATE'S CURRENT AND PLANNED MARKET PARTICIPATION?**

A: As identified in Proceeding No. 23M-0195E, Tri-State plans for its loads, resources, and transmission system in the Western Area Power Administration Colorado-Missouri Region ("WACM") balancing authority to join the Southwest Power Pool ("SPP") Regional Transmission Organization ("RTO") in the Western Interconnection on April 1, 2026. In Tri-State's 2023 ERP Phase I modeling, we simulate the impact of this portion of our system entering the market by increasing market sales and purchase depths starting in 2026. Additional detail on the specific depths and assumptions can be found in **Attachment B** ~~of the ERP Report (**LKT-1**).~~ LKT-7

**Q: IS THIS A REASONABLE MODELING APPROACH?**

A: Yes. Because Tri-State does not yet have the capacity to employ a nodal model, adjusting market depth parameters is the best approach available. As Tri-State continues to make progress toward SPP RTO market participation for its WACM load and resources, we anticipate transitioning our EnCompass model to employ a nodal approach for the 2027 ERP.

## VI. SENSITIVITY ANALYSES

**Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A: In this section of my Direct Testimony, I discuss the two sensitivity analyses that Tri-State modeled for each scenario.

**Q: WHAT SENSITIVITIES DID TRI-STATE MODEL?**

A: Tri-State assessed each scenario's performance under two sensitivity analyses—one that simulated extreme weather event ("EWE") conditions and one that evaluated High Gas prices.

**Q: PLEASE DESCRIBE THE SENSITIVITY ANALYSES TRI-STATE COMPLETED FOR EACH SCENARIO.**

A: For each scenario, Tri-State tested system performance under both EWE and High Gas conditions, separately. For the EWE sensitivity, transmission, load, renewable and thermal generation, and gas and power market prices were stressed (as described in **Attachment B-5** of the ERP Report (**LKT-1**)) for a one-week period in each winter and summer season during the Resource Acquisition Period ("RAP") to evaluate each scenario's performance under those conditions. Each scenario maintains its base expansion plan throughout the sensitivity analyses, but each scenario is re-dispatched in EnCompass with the stressed parameters to model the impact of an extreme weather or high gas event.

LKT-12

The approach to EWE sensitivity modeling in Phase I of the 2023 ERP is different from the approach in Phase II of the 2020 ERP in that the EWE stress assumptions are included in the modeling of each scenario's expansion plan. This approach resolved the issue that occurred in the 2020 ERP Phase II of scenarios

not meeting the Level II reliability metrics under initial modeling runs due to lack of expansion plan visibility into the EWE parameters. The base dispatch for each scenario does not reflect the EWE stress, to enable assessment of the financial results for each scenario under assumed normal system conditions.

For the High Gas sensitivity, stressed gas and power market prices[10] were applied in the modeling to evaluate each scenario's financial performance under that condition (as described in **Attachment** ~~**E** of the ERP Report (**LKT-1**)~~ LKT-25, providing another look at dispatch results.

**Q: DID TRI-STATE ENGAGE STAKEHOLDERS IN IDENTIFYING AND DEVELOPING THE SENSITIVITIES MODELED?**

A: Yes. Tri-State held several meetings with interested stakeholders between January 17 and July 19, 2023, prior to beginning modeling, to discuss potential scenarios and sensitivities to be modeled and Tri-State's approach to EWE data and related reliability metrics. During those meetings, Tri-State reviewed potential scenarios and sensitivities and made adjustments based on stakeholder feedback. Tri-State also shared its approach to the EWE stress, detail on historical EWE data evaluated, planned EWE resource and transmission stresses and how each differed from the 2020 ERP Phase II EWE modeling, and provided options for potential approaches to the EWE load stress for stakeholder input. These meetings are identified in ERP Report (**LKT-1**).

**Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE EWE SENSITIVITY?**

[10] Market prices are provided by a third-party vendor, Horizons Energy—a analytics, data, and consulting company.

A: The EWE sensitivity simulates a 168-hour period in the summer and in the winter where extreme weather occurs, during a forecasted peak load period and resource availability and system operations are constrained. The EWE stress assumptions are described in detail within **Attachment ~~B-5~~ LKT-12** of the ERP Report (**~~LKT-1~~**) and reflect modifications from historical EWE conditions to address the Commission's statement in Decision No. C23-0437 that "…an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs."[11]

**Q: PLEASE DESCRIBE THE DATA INPUTS FOR THE EWE SENSITIVITY.**

A: Tri-State primarily utilized historical data from EWE periods to develop EWE sensitivity stresses. These data informed the length of the EWE, the initial resource profiles, and expected transmission constraints. The following periods of historical EWEs were evaluated:

- July 2018 Heat Wave: 7/7-7/11 (5-day event)
- July 2022 Heat Wave: 7/17-7/19 (3-day event)
- Feb 2021 Winter Storm Uri: 2/13-2/17 (5-day event)
- Dec 2022 Winter Storm Elliot: 12/21-12/26 (6-day event)

Tri-State also utilized renewable resource performance profiles from some of these events, where available for existing resources on the Tri-State system. EWE stress data is applied on a regional basis, reflective of Tri-State system diversity. From these data, Tri-State made any necessary adjustments to reflect a

[11] Decision No. C23-0437, at ¶ 57.

reasonable time period for events (month of occurrence and length of days), to sync profiles of resource stresses to load as both are impacted by weather, and to ensure a robust but reasonable stress not solely based on past weather conditions. The approach to these adjustments is described in **Attachment ~~B-5~~** ~~of the ERP Report (**LKT-1**).~~ LKT-12

**Q: BEYOND THE CHANGE IN APPROACH TO MODELING, WHAT INPUT ASSUMPTIONS WERE CHANGED FOR EWE SENSIVITIES SINCE THE 2020 ERP?**

A: Nearly all of the EWE modeling assumptions were modified for the 2023 ERP. Data input assumption modifications for the EWE sensitivity include:

- **Length of EWE:** The timeframe for each EWE was shortened from two weeks to one week (168 hrs).
- **Load Stress:** Instead of a 90 percent confidence interval load stress applied equally to each hour, the load stress was based on a statistical model difference between the actual storm event weather in terms of precipitation for the month of the event and temperatures and 10-year weatherized normal weather by region. The EWE week was grossed up by the difference and the shape of the storm replaced the normalized shape used for the storm week. EWE dates were selected such that the demand peak in the months with EWE overlapped with the peak date of the storm. Please see the Direct Testimony of Lisa A. Lynn for additional detail on the load forecast assumptions and the extreme weather load forecasting methodology.

- **Renewable Resource Stress:** Renewable resource stresses were based on historical actual performance of renewable resources during prior EWEs where available, as well as actual wind speed or solar irradiance during prior EWEs. Renewables were stressed by an additional percentage, by region, for 72 hours during the peak period of the EWE to reflect that future events can be more severe than past events.
- **Thermal Resource Stress:** Outages and derates for existing thermal units were applied based on actual performance during historical actual EWEs.
- **Transmission Constraint Stress:** The TOT 3 transmission path (a corridor between southern Wyoming and northern Colorado) was reduced to 75 percent of Tri-State's share of its transfer capacity for three days during the winter EWE, and six hours (HE16-HE21) of every summer EWE period.
- **Limited Availability of Market Purchases:** Market purchases were modeled in the dispatch as available during limited hours of each EWE.

Each of these stresses are described in **Attachment ~~B-5~~** LKT-12 to the ERP Report (~~**LKT-1**~~).

**Q: DID TRI-STATE EVALUATE THE POTENTIAL FOR APPLYING A PROBABILISTIC MODELING APPROACH TO EWE?**

A: Given the short period of time between receipt of the 2020 ERP Phase II decision[12] and the start of 2023 ERP Phase I modeling, Tri-State was not able to consider the pursuit of probabilistic modeling for the EWE sensitivity. Tri-State will continue

[12] Decision No. C23-0437, at ¶56 (Proceeding No. 20A-0528E).

to evaluate opportunities to further enhance approaches to EWE sensitivity modeling over time.

**Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE HIGH GAS SENSITIVITY?**

A: The only modification for the High Gas Sensitivity is to stress the gas and electric prices, to assess scenario performance. High Gas Sensitivity assumptions and results are provided in **Attachment E** ~~of the ERP Report (**LKT-1**).~~ LKT-25

**Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**

**PROCEEDING NO. 23A-____E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN**

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**VERIFICATION**

---

STATE OF ____COLORADO____ )
) ss:
COUNTY OF __ADAMS_____ )

I, Brian Thompson, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Subscribed and sworn to before me this 16th day of November 2023, at Westminster, Colorado.

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

By: _____
Brian Thompson
Resource Planning Manager

Witness my hand and official seal.

_____
Notary Public

My Commission expires: 12/28/25.

Kimberly M. Strasburger
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134072316
MY COMMISSION EXPIRES December 28, 2025

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit EE: PRPA, *2024 Integrated Resource Plan* (Apr. 2023)

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Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

2024

# Integrated Resource Plan



Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

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# Glossary

| Term or acronym | Definition |
|---|---|
| **ATB** | Annual Technology Book |
| **BE** | Beneficial building electrification |
| **CDPHE** | Colorado Department of Public Health and Environment |
| **CIG** | Colorado Interstate Gas |
| **CPI** | Consumer Price Index |
| **DER** | Distributed energy resources |
| **DG** | Distributed generation |
| **DR** | Demand response |
| **ELCC** | Effective Load Carrying Capability |
| **EPA** | U.S. Environmental Protection Agency |
| **EPRI** | Electric Power Research Institute |
| **ERCOT** | Electric Reliability Council of Texas |
| **EV** | Electric vehicle |
| **GW** | Gigawatt |
| **GWh** | Gigawatt-hour |
| **HVAC** | Heating, ventilation and air conditioning |
| **IRP** | Integrated resource plan or integrated resource planning process |
| **ITC** | Federal solar tax credit |
| **JDA** | Joint dispatch agreement |

**LOLE** ..... Loss of Load Expectation

**LOLH** ..... Loss of Load Hours

**MISO** ..... Midcontinent Independent System Operator

**MW** ..... Megawatt

**MWh** ..... Megawatt-hours

**NEM** ..... Net energy metering

**NEVI** ..... National Electric Vehicle Infrastructure Formula Program, a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors

**NREL** ..... National Renewable Energy Laboratory

**ODTY** ..... One Day in Ten Years

**PPA** ..... Power purchase agreement

**PRM** ..... Planning reserve margin

**RDP** ..... Resource Diversification Policy

**RFP** ..... Request for proposals

**RP22** ..... Platte River's Resource Plan 2022

**RTO West** ..... Regional Transmission Organization West

**SPP** ..... Southwest Power Pool

**TOU** ..... Time of use

**VPP** ..... Virtual power plant

**WAPA** ..... Western Area Power Administration

**WECC** ..... Western Electricity Coordination Council

**WEIS** ..... Western Energy Imbalance Service market

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# 01 Executive summary

Platte River Power Authority's 2024 Integrated Resource Plan (IRP) presents a comprehensive strategy to reduce carbon emissions for the communities we serve in Northern Colorado while upholding our foundational pillars of reliability, financial sustainability and environmental responsibility. Developed amidst unprecedented market changes, the IRP addresses the challenges of long-range planning by evaluating various decarbonization scenarios and incorporating feedback from our board of directors, customers and stakeholders.

The IRP explores a diverse range of resource options for continuing our work toward the Resource Diversification Policy (RDP) goal, including renewable energy, battery energy storage, distributed generation, energy efficiency and demand response. The plan also shows how we will maintain reliability with an energy portfolio composed primarily of weather-dependent, renewable resources.

Given the inherent uncertainties in long-term planning, the IRP is based on projections of future electricity demand, costs of renewable resources, advancements in technology, and evolving market and regulatory environments. Acknowledging that these factors will change, the plan is intended to serve as a roadmap, allowing for adjustments and modifications to optimally reflect changing market conditions and continue the implementation of our decarbonization strategy.

This IRP informs Platte River's next steps toward achieving a low-carbon energy portfolio by illustrating how we will reduce carbon emissions by at least 80% below 2005 levels by 2030 to meet state goals, and by supporting our board-adopted RDP.



## Outreach and engagement

Building on what we learned from the last IRP, we expanded our outreach and engagement efforts considerably for the 2024 IRP.

We partnered with our owner communities to help educate customers about the relationship between Platte River and their cities. Over a six-month period, we presented our IRP process and updates to numerous community organizations, stakeholder groups and city leadership. We coupled these presentations with two engagement sessions hosted by Platte River to share IRP milestones, and offered digital resources including a dedicated website, email address and robust database of frequently asked questions and answers.

The feedback we collected between June and November 2023 helped inform the development of the portfolios.



## Portfolios

The IRP is designed to align Platte River's future portfolio with our continued work toward the RDP, with a primary focus on reducing carbon while maintaining reliability. All portfolios will emit some carbon in 2030 because commercially viable noncarbon dispatchable options are not available. After 2030, we model no new thermal generation and plan for long-duration energy storage. Energy prices assumed embedded carbon taxes in the evaluation of each portfolio.

**No new carbon:** Focuses on wind, solar and energy storage, testing the viability of excluding new thermal generation to meet demand and reliability.

**Minimal new carbon:** Adds a modest amount of new thermal generation (80 megawatts) to support reliability and evaluates potential emerging technologies.

**Carbon-imposed cost:** Adds a carbon cost to discourage new carbon-emitting resource additions to the resource mix.

**Optimal new carbon:** Balances cost, reliability and carbon considerations between the additional new carbon and carbon-imposed cost portfolios.

**Additional new carbon:** Presents a least-cost portfolio without specific carbon constraints, prioritizing cost and reliability.



Because external risks to executing the clean energy transition have substantially increased, Platte River developed a risk-adjusted plan to address the challenges of integrating renewable resources as modeled. The primary risks are supply chain issues; engineering, procurement and construction delays; regulatory uncertainty on pricing; the mismatch in timing between customer demand and the availability of renewable generation; and market price volatility. This plan also allows for adjustments to market prices, emerging technologies and regulatory developments.

# Conclusion

We are pleased to present the third iteration of the resource plan since our board passed the RDP. While we have made significant progress diversifying our portfolio since 2018—adding renewable energy to serve about one third of the owner communities' energy needs on an annual basis—we will immediately begin work on the fourth iteration as factors continue to change and evolve around us.

As you review our latest plan, we hope you take away a greater understanding of the complexity and challenges of replacing coal with renewables, firming up the intermittency of renewables with dispatchable resources, and doing right by the owner communities and our employees while pursuing one of the most accelerated decarbonization goals in the country.

This clean energy transition is a journey that will continuously evolve with changing circumstances and advancements in technology. Platte River is committed to making the transition on behalf of the owner communities to create a diverse, low-carbon energy portfolio for a sustainable future.

# 02 Introduction



Platte River Power Authority's 2024 IRP is a living document that guides and informs our efforts to supply reliable, environmentally responsible and financially sustainable energy and services to our owner communities while we work toward a noncarbon energy future. Throughout this document, we highlight how Platte River will address high-level policy goals while incorporating staff recommendations and research, third-party studies, and legislative, regulatory, market and technology changes.

Platte River developed this IRP with involvement from our owner communities and their customers. The board of directors approved the previous IRP document in 2020. Platte River is required to update the IRP and file it with the Western Area Power Administration (WAPA) every five years.

The report is organized as follows:

- The remainder of this section provides a general overview, background and history of Platte River, illustrating the foundational pillars and board-adopted policy that guide our planning activities and decisions.
- While IRPs are common among electric utilities, Platte River's approach is unique. Chapter 3 describes our process and timeline, the progress we made since our last IRP, and the industry challenges we face, including persistent impacts from the COVID-19 pandemic. Chapter 4 further highlights the variables and challenges Platte River faces as we pursue a clean, reliable energy future.
- Most of the report provides technical background data, assumptions and methodology that influence and shape our IRP, including demand, impacts of distributed energy resources (DER) and electrification, supply-side assumptions, extreme weather events and more. Chapter 7 of this report details the IRP design, including the studies, portfolios and our modeling methodology.
- Chapter 8 shows our modeling results; Chapter 9 highlights the resulting action plan from this IRP.



# Public power utilities

Platte River is one of more than 2,000 community-owned electric utilities in the U.S. These utilities are operated by local governments and provide their owner communities with reliable, responsive, not-for-profit electric service. Public power utilities serve one in seven electricity customers across the U.S. – more than 54 million citizens – and operate in 49 states and in several U.S. territories.[1]

The American Public Power Association emphasizes the following characteristics of public power utilities:

- **Service-oriented:** We exist to serve and add value to our owner communities.
- **Community-owned:** We help advance the good of the community.
- **Local control and decision-making:** Decisions reflect our owner communities' needs and values.
- **Not-for-profit:** We focus on safely providing reliable, environmentally responsible and financially sustainable energy and services.
- **Responsive:** Because we are part of our communities, we react quickly to their needs.

[1] American Public Power Association website, www.publicpower.org








## **2.1** Platte River overview

Until the mid-1960s, many Colorado municipal utilities separately received wholesale electric service from the Bureau of Reclamation's system of hydroelectric generating facilities throughout the Colorado and Missouri River basins. In late 1965, 31 municipal utilities created the Platte River Municipal Power Association to manage and protect their collective hydropower rights, particularly due to the Bureau's announcement that it could not meet growing energy needs beyond the mid-1970s and no new (hydroelectric) energy projects would be built.

In 1973, four of the original 31 municipal utilities—Estes Park, Fort Collins, Longmont and Loveland—collaborated to pass legislation to form the Platte River Power Authority, a not-for-profit entity that would provide its owner communities with long-term energy above their limited allotment of federal hydropower. Following voter approval of a constitutional amendment, Platte River reformed in 1975 as a joint action agency, empowered to acquire assets to better serve its owner communities. These assets are discussed in greater detail throughout this document.

Also in 1975 (after the Colorado legislature passed enabling legislation), the four communities signed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is the agreement between the four owner communities that creates Platte River, establishing its purpose and governance structure.

Platte River is governed by an eight-person board of directors. The board includes the mayor (or a designee of the mayor) of each owner community and four other directors who are appointed to four-year staggered terms by the governing bodies of the owner communities. The board meets nine times per calendar year to establish and guide policy for the organization.

## 2.1.1 Foundational pillars

Platte River is guided by three pillars that drive its mission. Together with our vision and values, these pillars inform all activities and serve as the foundation for Platte River's decarbonization efforts.

### Reliability

Providing a highly reliable supply of power to our owner communities

### Environmental responsibility

Achieving noncarbon energy goals and protecting our natural resources

### Financial sustainability

Managing financial risks, providing stable, competitive wholesale rates that generate adequate cash flow and maintain access to low-cost capital

## 2.1.2 Vision, mission and values

### Our vision

To be a respected leader and responsible power provider improving the region's quality of life through a more efficient and sustainable energy future.

### Our mission

While driving utility innovation, Platte River will safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities of Estes Park, Fort Collins, Longmont and Loveland.



## Our values

**Safety:** Without compromise, we will safeguard the public, our employees, contractors and assets we manage while fulfilling our mission.

**Integrity:** We will conduct business equitably, transparently and ethically while complying fully with all regulatory requirements.

**Service:** As a respected leader and responsible energy partner, we will empower our employees to provide energy and superior services to our owner communities.

**Respect:** We will embrace diversity and a culture of inclusion among employees, stakeholders and the public.

**Operational excellence:** We will strive for continuous improvement and superior performance in all we do.

**Sustainability:** We will help our owner communities thrive while working to protect the environment we all share.

**Innovation:** We will proactively deliver creative solutions to generate best-in-class products, services and practices.

# Environmental leadership

Platte River continually demonstrates a strong commitment to environmental responsibility while safely providing reliable and financially sustainable energy and services to the four owner communities. Below are examples of our environmental stewardship:

- Incorporated state-of-the-art emissions controls on the coal-fired Rawhide Unit 1, consistently positioned among the lowest SO2-emitting coal-fired plants in the country, according to data available from the U.S. Environmental Protection Agency (EPA).
- Became the first utility in Colorado to offer wind energy to the owner communities through the Medicine Bow Wind Project in 1998.
- Began commercial operation of 30 MW of solar at the Rawhide Energy Station in 2016. Platte River later added another 22 MW of solar to the area, with a 2 megawatt-hour (MWh) battery storage facility.
- Completed construction of a new headquarters campus in Fort Collins in 2020 that is designed to serve as an example of energy efficiency. The campus received Gold LEED Certification by the U.S. Green Building Council in 2023.
- Adopted the Resource Diversification Policy in 2018, becoming one of the first utilities in Colorado and the country to set a goal of a 100% noncarbon energy mix by 2030.

## 2.2 Resource Diversification Policy

In 2018, Platte River's Board of Directors passed a landmark policy (Figure 1) that directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon energy resource mix by 2030 while maintaining the foundational pillars. The policy also lists several advancements (or caveats) that must occur for Platte River to meet this ambitious goal.

### Purpose

This policy is established to provide guidance for resource planning, portfolio diversification and carbon reduction.

### Policy

The board of directors (the board) directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

The board recognizes the following advancements must occur in the near term to achieve the 2030 goal and to successfully maintain Platte River's three pillars:

- An organized regional market must exist with Platte River as an active participant
- Battery storage performance must mature and the costs must decline
- Utilization of storage solutions to include thermal, heat, water and end user available storage
- Transmission and distribution infrastructure investment must be increased
- Transmission and distribution delivery systems must be more fully integrated
- Improved distributed generation resource performance



- Technology and capabilities of grid management systems must advance and improve
- Advanced capabilities and use of active end user management systems
- Generation, transmission and distribution rate structures must facilitate systems integration

Resource planning is an ongoing process and Platte River continuously evaluates opportunities to add noncarbon resources. Platte River reviews its generation portfolio annually as part of the budgeting and planning process. This process sets the foundation for developing an IRP submitted to the Western Area Power Administration every five years as required. The resource planning process includes evaluating the progress of energy storage, distributed power sources and new technologies. As a leader in the utility industry in Colorado for many years, Platte River will continue to move forward to meet the resource needs and wants of the four owner communities. The board recognizes the integration of noncarbon resources and new technologies will shape the future of Platte River's and the four owner communities' energy supply.

**Figure 1.** *Resource Diversification Policy*



# 03 IRP process overview

## 3.1 What is an IRP?

A utility IRP[2] compares the supply-side resources (generated or purchased by the utility) and demand-side resources (contributed by customers, including DER) with projected energy needs (load) and selects an optimal set of resources to meet future needs while meeting the regulatory requirements and policy goals at the highest level of reliability.

Key components of an IRP include:

- Customers' future electricity needs (or load forecast)
- Future costs and availability of supply and demand side resources
- Regulatory and policy requirements including environmental considerations
- Community engagement to hear stakeholder feedback and questions
- An assessment of future technologies

These components and other inputs are used in a complex planning and optimization model to develop a 10-to-20-year roadmap of investments to provide reliable supplies during the planning horizon. An IRP model optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM[3]) or other reliability criteria, to ensure adequate electricity supply under all reasonably expected variations of weather, customer demand and resource availability.

A key component of an IRP is an action plan that outlines the specific activities the utility plans to conduct in the next three to five years while developing the next IRP. An IRP is a snapshot in time; planning is an ongoing and dynamic process. An IRP acts as a roadmap or guide, while the actual investment decisions are made based on the best information available at the time of the decision.

[2] In this document the acronym IRP is used in two different ways–an integrated resource plan and as an integrated resource planning process

[3] PRM is defined as the additional generating capacity available to meet a future year peak demand. It is expressed as a percentage of peak demand. Historically, Platte River has maintained a 15% PRM which means if the load forecast expects a peak demand of 100 MW in a future year, Platte River would build or acquire 115 MW of generation or DER capacity to reliably meet that peak demand.

## 3.2 Why do an IRP now?

In 2020, Platte River developed an IRP that outlined several paths to work toward the RDP goal. The plan's recommendations were developed before the global COVID-19 pandemic, which put many things on hold for two years, including construction of renewable energy projects. The pandemic triggered widespread supply chain issues and contributed to increased costs for labor, capital, equipment and new resources, which resulted in multiple rounds of contract renegotiations for renewable projects. State and federal clean energy policies also created intense competition for renewable resource projects and related equipment and staffing.

Meanwhile, Winter Storm Uri in February 2021 was a wakeup call about the increased frequency of extreme weather events and the need for a reliable power supply. While the emergence of new technologies and the passage of the Inflation Reduction Act are positive developments, the industry continues to face inflationary pressures and supply chain challenges.

This 2024 IRP captures these developments, re-affirms our commitment to the RDP and charts a path toward that goal. While Platte River is not required to file an IRP with WAPA before 2025, we expedited this IRP to support the accelerated integration of renewable resources. We finalized our assumptions underlying this IRP in summer 2023, so this IRP provides portfolios or snapshots of the future viewed from 2023. This IRP will need updating as technology and circumstances evolve. Platte River will prepare the next IRP in 2028.

### 3.2.1 IRP timeline

The 2024 IRP process started in 2022 by commissioning pre-IRP studies from external consultants and continued through early 2024. Figure 2 illustrates a high-level timeline and list of major activities. Community engagement is an important part of the IRP process and is highlighted in yellow.

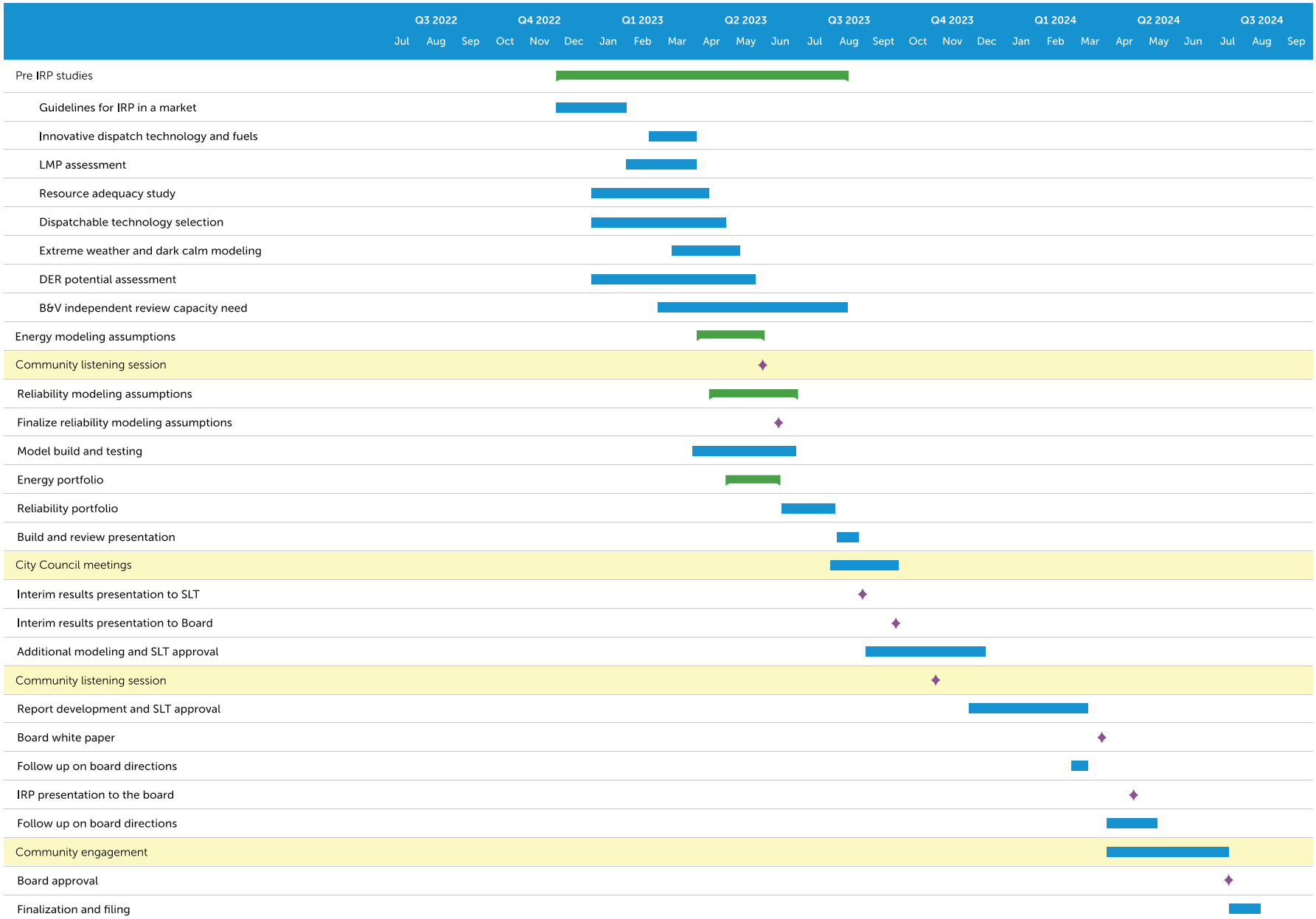



**Figure 2.** *Timeline of 2024 Integrated Resource Plan activities and milestones*

## 3.3 Progress since the last IRP

Platte River continued to work toward achieving the RDP after submitting our last IRP, acquiring more renewable generation, expanding efforts to join a regional market and working with the owner communities to expand DERs. Specific annual achievements are summarized below.

### 2020

- Began receiving energy from the Roundhouse Wind Energy Center, a 225-megawatt (MW), 80-turbine wind farm. Additionally, Platte River purchased the 230-kilovolt generator outlet line from the project, securing energy delivery to the owner communities throughout the 22-year power purchase agreement (PPA).
- Launched the DER strategy committee with staff members from Platte River and the owner communities. The DER strategy committee explores how to integrate systems that will better balance supply and demand as we transition our energy portfolio.
- Finalized closure dates for remaining coal units in Platte River's portfolio. Rawhide Unit 1 will close by the end of 2029, 16 years before its planned retirement. Craig Unit 2 will close by September 2028. (The 2025 closure date for Craig Unit 1 was announced in 2016.)
- Signed a PPA to build Platte River's largest solar project, which, when operational, will provide up to 150 MW of power.

### 2021

- Commissioned the 22 MW Rawhide Prairie Solar project, including a 2 megawatt-hour battery.
- Created the transition and integration division, combining DER and energy solutions with resource planning and information and operations technology departments to foster the innovation needed to achieve a noncarbon electric system that includes integrated DERs.
- Together with the owner communities, developed a comprehensive DER strategy providing a path forward to jointly attain the full value of DERs to the benefit of customers and the grid.
- The Efficiency Works Business team launched the Community Efficiency Grant to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community.
- Issued a request for proposals (RFP) to competitively procure up to 250 MW of solar generation and co-located battery resources connected at the distribution or transmission level.

## 2022

- Accelerated the timeline for new noncarbon energy resources to maintain the reliability and financial sustainability of the resource portfolio ahead of retiring coal-fired generation resources.
- Confirmed the purchase of 150 MW of solar energy from the vendor for the Black Hollow Solar project, restating an agreement originally signed in 2020. Logistical challenges delayed the project, now scheduled to begin commercial operation in 2025.
- Analyzed and evaluated large-scale four-hour storage and longer duration energy storage and evaluated adding an additional wind project to Platte River's portfolio. Developed a revised portfolio (RP22) that added about 105 MW more capacity by 2030 than the 2020 IRP. RP22 called for 450 MW of solar, 300 MW of wind, 200 MW of four-hour storage and 166 MW dispatchable thermal generation.
- Together with the joint dispatch agreement (JDA) partners, Platte River announced plans to join the existing Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP). The WEIS replaces the JDA and allows Platte River to gain experience operating in a larger imbalance market. Investments began in 2022 to prepare for entry into the WEIS.
- Launched an interactive electric vehicle (EV) shopper guide website with information on currently available EVs, including cost, performance specifications and available incentives, as well as a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles.



### 2023

- Issued an RFP to competitively procure 150-250 MW of wind generation. Responses to the RFP were received in late 2023, with evaluation of the responses continuing in 2024.
- Began operating in the SPP WEIS market.
- Selected a vendor for battery storage facilities located in the owner communities. The projects' expected capacity will range from 20-25 MW, consisting of four-hour duration lithium-ion batteries.
- Expanded the EV website to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions.
- Enhanced program offerings through the partnership between Efficiency Works and Energy Outreach Colorado to actively engage with participants on more significant home upgrades including energy efficiency and building electrification, resulting in nearly $1 million of investments to support the income-qualified residential upgrades in Platte River's owner communities.
- Expanded Efficiency Works programs to include multiple building electrification measures, supporting 359 heat pump installations with over $1 million in incentives to help customers to overcome financial hurdles and investing nearly $10,000 training local contractors on building electrification.
- Actively supported over 100 income-qualified customers to upgrade their homes, with plans to support over 250 customers annually in future years.
- Signed a commitment agreement to join the SPP Regional Transmission Organization West (RTO West) on April 1, 2026.
- Committed to advancing EV infrastructure by launching one of the highest incentives in the state, of $5,000 per public charging port, to promote public charger hosting by local business and multifamily properties by offsetting some of the installation cost.

## 3.4 External developments since the 2020 IRP

### 3.4.1 Pandemic

The COVID-19 pandemic brought unprecedented challenges worldwide and the power sector was no exception. Immediately after the pandemic started, the economic slowdown resulted in electricity demand reduction and changing demand patterns. As economic activity slowly resumed, the electricity demand started coming back with residential demand increasing (compared to pre-

[4] https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary

pandemic levels) due to a significant increase in citizens working from home.

Supply chain slowdowns are among the pandemic's biggest impacts and are detailed in the next section. The pandemic also slowed down construction and new renewable project development due to reluctance of investors to commit capital amid market volatility and uncertainty about future energy demand.

As the world began adapting and recovering after the first few months of the pandemic, it prompted many governments to reevaluate energy policies and regulatory frameworks to address emerging challenges and support economic recovery efforts. The pandemic also highlighted the importance of resilient and sustainable energy systems. Significantly higher demand and sustained challenges with supply chains contributed to the cost of renewable resources and energy storage projects nearly doubling post pandemic.

### 3.4.2 Supply chain issues

Supply chains were impaired by factory shutdowns, component shortages, labor shortages and financial, economic, demand and policy uncertainty during the pandemic. While this slowed down the supply side of electricity, the demand side recovered quickly and in fact, significantly increased. Renewable energy project supply chains are global and reflect worldwide demand. According to the International Energy Agency, the world added less than 200 gigawatts (GW) of new renewable resources in 2019 and more than 440 GW in 2023.[4] Although renewable supply chains are recovering from pandemic-related stress, the surge in demand is increasing pressure. In the U.S., the Inflation Reduction Act has significantly increased incentives to expand the domestic supply chain of renewable generation. But this further strains the supply chain as companies rush to develop U.S. renewable manufacturing.

This supply chain pressure directly impacts Platte River's resource procurement. For example, Platte River conducted an RFP in 2019 to add 100-200 MW of new solar capacity by 2023. The winning project, a 150-MW solar farm called Black Hollow Solar, is now expected to start commercial operation in 2025. Similar risks exist for projects planned for 2026 and 2027.



### 3.4.3 Renewable resource pricing

Due to supply chain issues and increased demand, the prices for renewables have significantly increased since the last IRP. As shown in Figure 3 from Level Ten Energy[5], PPA prices in the U.S. doubled by the end of 2023 compared to 2020 levels.

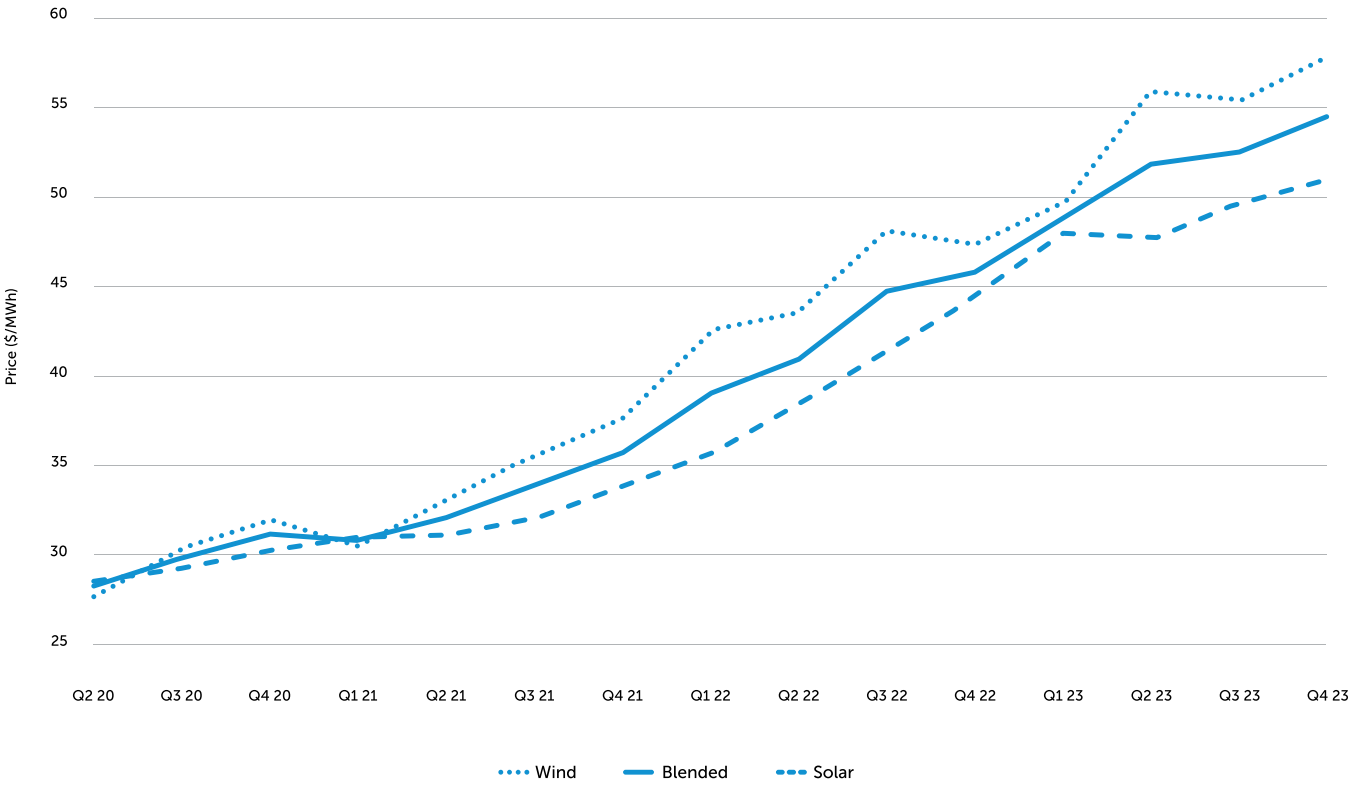



**Figure 3.** *PPA prices in the U.S. between 2020 and 2023*

Major drivers for this price increase are higher demand, higher cost of capital, higher inflation rates, higher transmission costs, higher risk premiums and trade policy changes. These drivers are detailed below.

**Higher demand:** Consistent with the global increase in demand for renewable generation, demand in the U.S. has also increased, especially after the passage of the Inflation Reduction Act, as illustrated in Table 1. According to the U.S. Energy Information Administration (EIA), the U.S. is expected to add 62.8 GW[6] of new capacity in 2024, 55% more than the 40.4 GW added in 2023. This represents the most capacity added annually since 2003.

Of this new capacity, the 36.4 GW of added solar is double the 18.4 GW added in 2023. Expected 2024 battery storage additions of 14.3 GW will be more than double the 6.3 GW added in 2023. The significant increase in demand for renewable energy, both domestically and globally, puts upward pressure on prices.

| | 2023 | 2024 |
|---|---|---|
| New capacity | 40.4 GW | 62.8 GW |
| Solar | 18.4 GW | 36.4 GW |
| Battery | 6.3 GW | 14.3 GW |

**Table 1.** *U.S. demand for renewable generation*

**Higher cost of capital:** Most of the renewable projects built by third-party developers and sold under long term PPAs are financed with up to 80% debt. Therefore, interest rates (especially long-term debt rates) affect PPA prices. U.S. long-term interest rates, as measured by the yield on 10-year U.S. Treasury Securities, have more than doubled in the past few years as shown by Figure 4 from the Federal Reserve's Economic Data.[7]

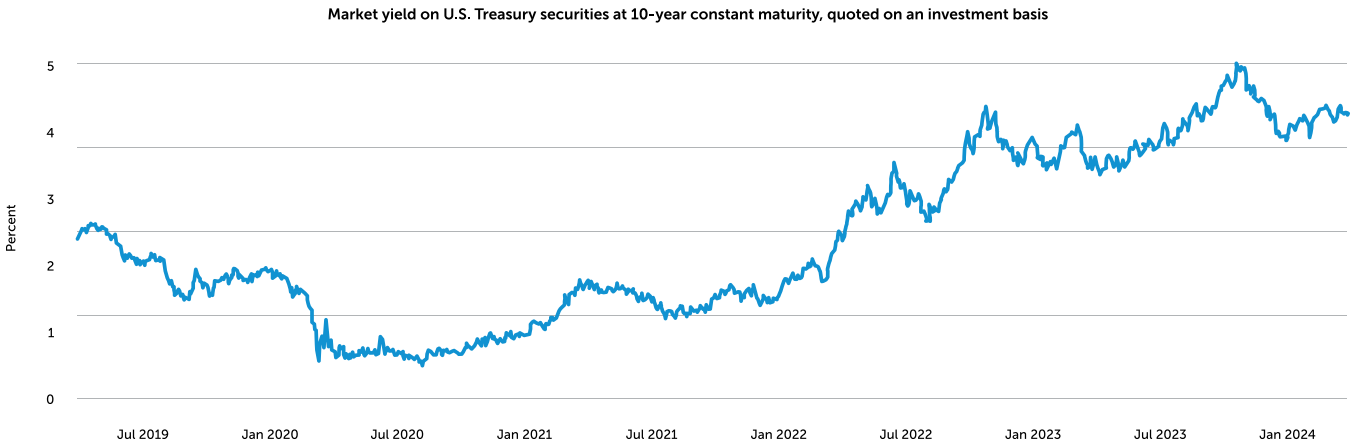



**Figure 4.** *Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis*

[5] https://www.leveltenenergy.com/ppa

[6] https://www.eia.gov/todayinenergy/detail.php?id=61424

[7] https://fred.stlouisfed.org/series/DGS10

Corresponding to the 10-year Treasury Securities yield increases, the developer's cost of capital for financing a project has approximately doubled over the last few years from 3-4% to over 7%. This increased cost of debt has significantly increased the carrying cost of projects, raising PPA prices for utilities.

**Higher inflation:** According to the U.S. Bureau of Labor Statistics, the Consumer Price Index (CPI), which is a general measure of inflation, increased 17% in the past three years (January 2021 to January 2024), almost three times the prior three-year period (January 2018 to January 2021), when it increased 6%. This increase in CPI has affected all sectors of the economy, including the price of renewable generation. More specifically, labor costs have seen significant increases in the past few years as shown in Figure 5.

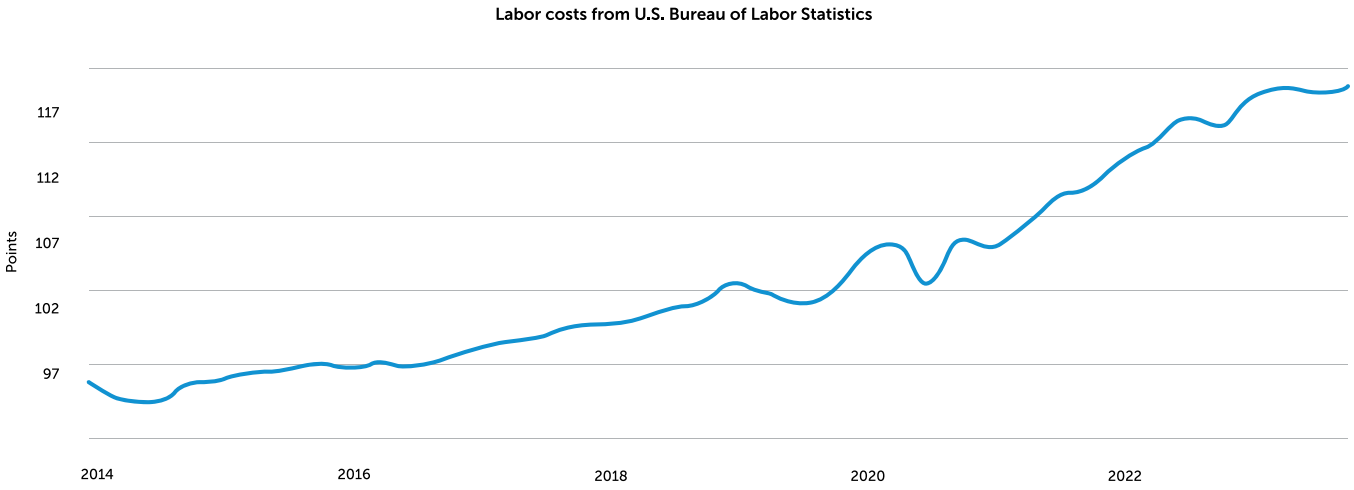



**Figure 5.** *Labor costs from U.S. Bureau of Labor Statistics*

Similarly, metal costs have seen more volatility and net increase over the past few years, as shown in Figure 6.[8]

**Higher transmission costs:** Transmission costs to interconnect renewables are increasing at two levels. First, inflation increases transmission interconnection equipment costs. Second, as more and more renewable resources are added to the grid, the cost to interconnect the next renewable project is often higher due to the need to upgrade the existing transmission infrastructure.

[8] https://fred.stlouisfed.org/series/PMETAINDEXM

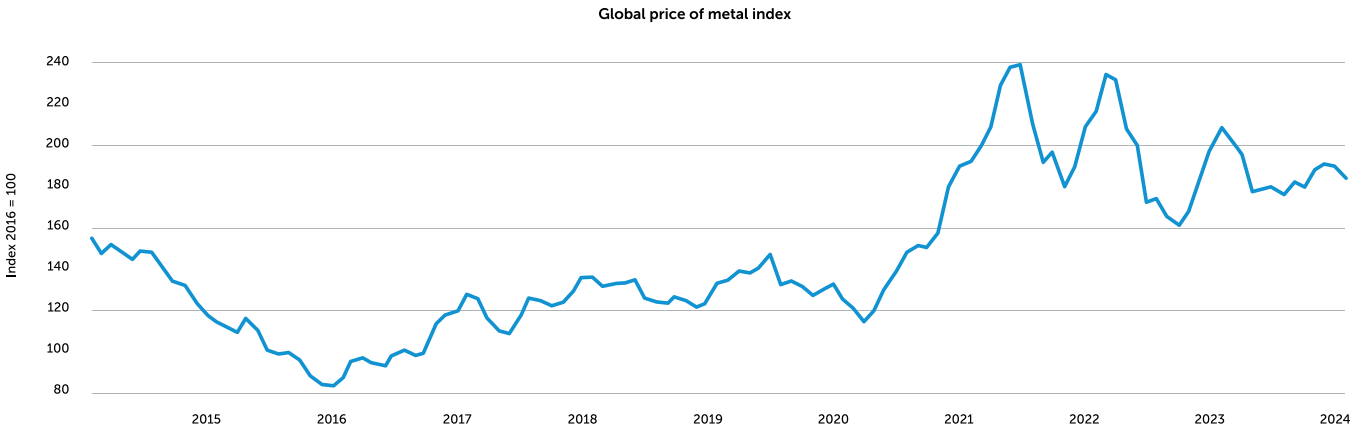



**Figure 6.** *Global price of metal index*

**Higher risk premiums:** Recent inflation and uncertainty about future inflation mean that developers assume the recent increase in equipment and labor prices will continue in the future. For example, developers have experienced a significant increase in engineering, construction, and procurement costs and assume these annual cost increases will continue. Recently, Platte River agreed to higher pricing on previously signed PPAs to enable project construction.

Additionally, Anti-Dumping and Countervailing Duties and Uyghur Forced Labor Prevention Act policies created uncertainty for imports from certain countries. These policies, coupled with other factors mentioned earlier, has pushed the price of renewable generation higher. The Inflation Reduction Act and other policies will expand domestic manufacturing, but it may take years before we see any downward pressure on prices.



# 3.5 Resource planning refresh in 2022

Following the pandemic and associated impacts on cost, Platte River staff updated the recommended portfolio from the 2020 IRP in 2022. The revised plan is called RP22 and includes the following:

## 3.5.1 Acceleration of renewable integration

The 2020 IRP had assumed all new generation and storage would come online on Jan. 1, 2030, after Platte River's last coal plant closed. RP22 adds renewables, storage and dispatchable resources while considering project development timelines and supply chain issues. Platte River seeks to have most, if not all, new resources ready by 2028 to give at least one full year of operating experience to Platte River staff before retiring Rawhide Unit 1. This accelerated timeline shows a gradual increase in renewable generation after 2025.

## 3.5.2 Extreme weather modeling

While Platte River's 2020 IRP simulated average weather and load conditions, the impact of Winter Storm Uri in February 2021 on power supply across the midsection of the continental U.S. provided a valuable lesson for enhancing future power supply reliability. During Uri, northern Colorado experienced extremely cold weather and saw little to no renewable generation for three days. We refer to this event of no renewable generation as a "dark calm" and simulated these events in future planning.

To enhance the reliability of the future power supply, RP22 simulates 24 years of hourly historical weather (with its unique hourly load, wind and solar profiles) and dark calm events. To meet this enhanced reliability requirement, RP22 added 62 MW of additional dispatchable capacity and reduced reliance on four-hour storage relative to the 2020 IRP recommended portfolio.

## 3.5.3 Expanded DER impact

Working closely with our owner communities, Platte River completed its DER strategy in July 2021. The strategy brought an expanded focus on DERs. Since the completion of 2020 IRP, customers have rapidly adopted EVs and distributed solar. Similarly, there is increased interest in heating electrification to replace natural gas-fueled heating. As a result, RP22 models rapid growth in DERs, including EVs, heating electrification and demand response.

## 3.5.4 Renewable supply chain impact

As discussed above, the renewable generation costs and project lead times increased after the pandemic. RP22 considers these increased costs and longer development times for the future portfolio.

# 3.6 Regulatory environment

This section outlines the legislative, regulatory and policy environment in which Platte River developed this IRP. It covers current legislative requirements with which Platte River must comply (both state and federal) as well as political assumptions that influenced the resource plan. This IRP addresses applicable state and federal laws, including those highlighted below.

Platte River is accountable to its board, to the Colorado Department of Public Health and Environment (CDPHE) through commitments made in its voluntarily filed Clean Energy Plan, and to the EPA through its contributions to Colorado's regional haze state implementation plan. The Colorado Public Utilities Commission does not regulate Colorado municipal utilities.

## 3.6.1 Colorado policy review

Since the passage of Platte River's RDP in 2018, Colorado's legislature has increased its attention to energy and environmental policies. Many recent bills impact utilities' resource planning and operations. The following bills are relevant to Platte River's resource planning and this IRP:

**HB19-1261:** The Climate Action Plan to Reduce Pollution set aggregated and sector-specific targets for reducing statewide greenhouse gas pollution. The bill set aggregate reduction targets at 26% by 2025, 50% by 2030 and 90% by 2050 compared to 2005 levels. The General Assembly encouraged consumer-owned electric utilities to file Clean Energy Plans demonstrating at least an 80% reduction in emissions by 2030 compared to 2005 levels. Platte River subsequently filed a voluntary Clean Energy Plan in line with the standards of HB19-1261. In addition to rulemakings for utilities, HB19-1261 also ushered in sweeping changes for other sectors, such as transportation and buildings, that have a direct impact on future electric load and utilities' resource planning.

**SB19-096:** This bill directed CDPHE's Air Quality Control Commission to collect greenhouse gas emissions data from emitting entities and report on the data to support the state in meeting its greenhouse gas emission reduction goals.

**HB22-1244:** This bill created a new program within CDPHE's Air Pollution Control Division to regulate toxic air contaminants. It also gave the Air Quality

Control Commission permission to create air toxics rules more restrictive than those of the federal Clean Air Act. Starting in 2024, regulated organizations must submit annual toxic emissions reports that the Air Pollution Control Division will make available to the public.

**SB23-198:** Expressing legislative concern that utilities are on track to meet the greenhouse gas reduction goals set out in HB19-1261, this bill requires any utility that submitted a Clean Energy Plan before Jan. 1, 2024, to model at least one portfolio that achieves a 46% emissions reductions by 2027 (as compared to 2005 levels) and at least one portfolio that achieves greater emissions reductions than the Clean Energy Plan submitted. The Air Pollution Control Division must subsequently confirm that utilities have adequate resources to achieve the 2030 clean energy target. As part of this IRP process, Platte River's board will consider portfolios that meet the requirements of SB23-198.

Table 2 illustrates how these Colorado policies are either considered in Platte River's RDP, modeled in this IRP or apply only to reporting functions.

| Colorado policy | Reporting | Considered by RDP | Modeled by 2024 IRP |
|---|---|---|---|
| **HB19-1261:** The Climate Action Plan to Reduce Pollution | | ✓ | |
| **SB19-096:** Collect Long-term Climate Change Data | ✓ | | |
| **HB22-1244:** Public Protections from Toxic Air Contaminants | ✓ | | |
| **SB23-198:** Clean Energy Plans | | | ✓ |

**Table 2.** *How Colorado policies are considered, modeled or reported by Platte River*

In 2018, Colorado Governor Jared Polis ran on a platform of achieving 100% renewable energy by 2040 and continues to direct his staff to achieve this goal. To drive and monitor Colorado's adherence to the greenhouse gas emissions reductions goals set out in HB19-1261, the state released its first Greenhouse Gas Pollution Reduction Roadmap in January 2021.

Concurrent with this IRP process, the Polis administration published its Greenhouse Gas Pollution Reduction Roadmap 2.0 in February 2024, which will accelerate Colorado's clean energy goals.

### 3.6.2 Federal policy overview

As a hydropower customer of WAPA, Platte River must file an IRP with WAPA every five years. This IRP document complies with WAPA requirements as detailed in Appendix A.

On June 16, 2020, Platte River announced its plans to retire Rawhide Unit 1 no later than Dec. 31, 2029. Colorado incorporated Unit 1's planned retirement into its state implementation plan for the regional haze program, making the retirement federally enforceable.

The U.S. Congress passed the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law, in 2021 and the Inflation Reduction Act in 2022. Together these bills resulted in unprecedented federal investments in the clean energy transition through tax credits (including for not-for-profits that have historically not paid taxes and therefore have not been eligible for tax credits) and competitive grant programs. In response, Platte River has dedicated resources to submitting grant applications and to exploring tax credits for new renewable energy assets. To date, Platte River has mainly captured these benefits through PPAs with renewable developers, whose prices reflect federal subsidies. In partnership with trade associations such as the American Public Power Association and Large Public Power Council, Platte River is continuing to explore opportunities.

Platte River is carefully monitoring the EPA's new regulations on power plants with coal- or new natural gas-fired generating units. In May 2024, the EPA finalized rules to reduce greenhouse gas emissions from power plants. Platte River will continue to closely follow these and other federal developments.



# 3.7 Stakeholder engagement process

## 3.7.1 Outreach strategy

Platte River's communications, marketing and external affairs team worked closely with the transition and integration team to develop a robust community engagement strategy for the 2024 IRP. We collaborated with the four owner communities' distribution utility communications and community relations staff. Owner communities' staff recommended which neighborhood groups, community and nonprofit organizations and customer accounts to engage and helped coordinate presentations for city councils and council-appointed boards. This allowed for a more targeted approach on engaging with stakeholders across Platte River's service region, responding to questions and addressing concerns surrounding the reliability, environmental responsibility and affordability of future energy portfolios.

### 3.7.1.1 Community meetings

While some owner community stakeholder groups knew Platte River as a wholesale power provider, many constituents were unaware who generates their power and how. An added value of the IRP community meetings was the opportunity for citizens to engage with their community-owned generation and transmission utility.

Mindful of equity and access, Platte River either visited every group we presented to or provided a virtual option, provided information in Spanish and equipped meetings with translators and listening assistance options.

While the audiences were widespread across Platte River's service region with diverse backgrounds, there were general themes that surfaced. Those themes include:

- Discussions around customer behavior changes and impacts to resource planning
- The increasing trend of beneficial electrification and growth in demand and load
- Impacts of climate change and extreme weather modeling
- Clarity on what is a dispatchable resource
- Equity and affordability


Timeline
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
April
May
June
Community engagement
Resource planning
• Pre-IRP studies
• Load forecasting
• Other inputs, assumptions

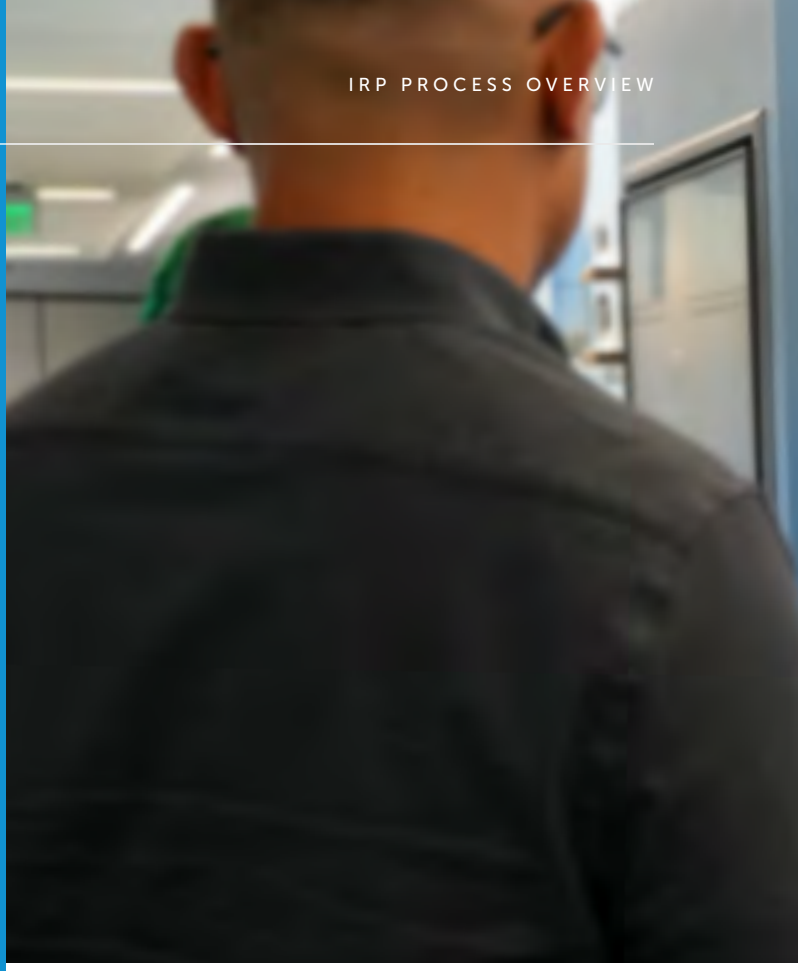
Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

Presentations per owner community:

- Estes Park: 2
- Fort Collins: 8
- Longmont: 5
- Loveland: 4

Presentations per community group type:

- Neighborhood group: 2
- Community organization: 6
- Nonprofit: 5
- Customer account: 1
- Council-appointed board: 3
- City/town councils: 4



### 3.7.1.2 Business community engagement

Platte River engaged the business community primarily through downtown development authorities and local chambers of commerce: the Estes Park Chamber of Commerce, the Fort Collins Area Chamber of Commerce, the Longmont Chamber of Commerce and the Loveland Chamber of Commerce. We presented to chamber staff, committee appointees and members, sharing information about Platte River, the RDP, the IRP process and forecasts of our shared energy future. We captured questions and feedback from the business community, who are integral drivers of economic and workforce development in the region.




### 3.7.1.3 Consulting with industry experts

Platte River's resource planning staff actively consulted with national institutes and public power councils, including the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL) and the Large Public Power Council.

## 3.7.2 Campaigns and resources

Platte River's first brand awareness and public education campaign launched soon after the start of our 2024 IRP community engagement. The parallel run of these two efforts aimed to educate the utility's service region about who Platte River is while driving users to Platte River's digital platforms to learn more about our aggressive decarbonization efforts.

Platte River used both organic and paid media to support community engagement activities for the 2024 IRP, including:

- Digital technologies like social media, email distribution and websites
- Cross-functional organic outreach through support from platforms across each owner community and distribution utility
- Paid media with advertisements placed in traditional and digital platforms with high visibility across each owner community
- Engagement with local media, including hosting an editorial meeting with local media partners



In addition, Platte River developed and maintains the following resources for continued engagement with the public.

#### 3.7.2.1 Microsite

Staff developed a detailed and interactive IRP microsite (prpa.org/2024irp) that is updated as information evolves and additional details are available. Members of the public are encouraged to visit this site to learn more about Platte River's plans and to access more in-depth information including the studies conducted as part of the IRP.

Our staff captured and answered all questions asked during the community engagement phase. These answers are provided in an appendix to this IRP. A subset of high frequency questions was extracted from the full list to develop a 'frequently asked questions' page published to the IRP microsite.

#### 3.7.2.2 Dedicated email

Platte River created a dedicated email for IRP specific questions and comments at 2024IRP@prpa.org. This approach allows for direct communication with engaged citizens and allows staff to track their contributions.

### 3.7.3 Results

The 2024 IRP reflects extensive collaboration among Platte River teams and gathering input from key stakeholders and the communities we serve. This process was designed to provide an open and transparent view of Platte River's resource planning strategy, accountability to our owner communities and the state of Colorado's clean energy goals and to underscore the value of equally maintaining our three foundational pillars.

One of the major takeaway messages we identified across each outreach effort: Platte River must continue to safely provide affordable and reliable power to its owner communities and their customers while addressing the evolving landscape in which we operate. Each owner community served by Platte River has set, or is in the process of setting, its own clean future initiative and is challenging Platte River to match these efforts to provide northern Colorado with electric service in an increasingly sustainable manner.

# 04

# Platte River's path to a clean, reliable energy future



# 4.1 Key variables and strategic considerations

Platte River considered whether the advancements identified in the RDP have been met while working toward the RDP goal. Other variables in this IRP include:

## 4.1.1 Load forecast

Load forecast refers to how load, or aggregate electricity demand, is changing and the impacts of those changes to the energy mix.

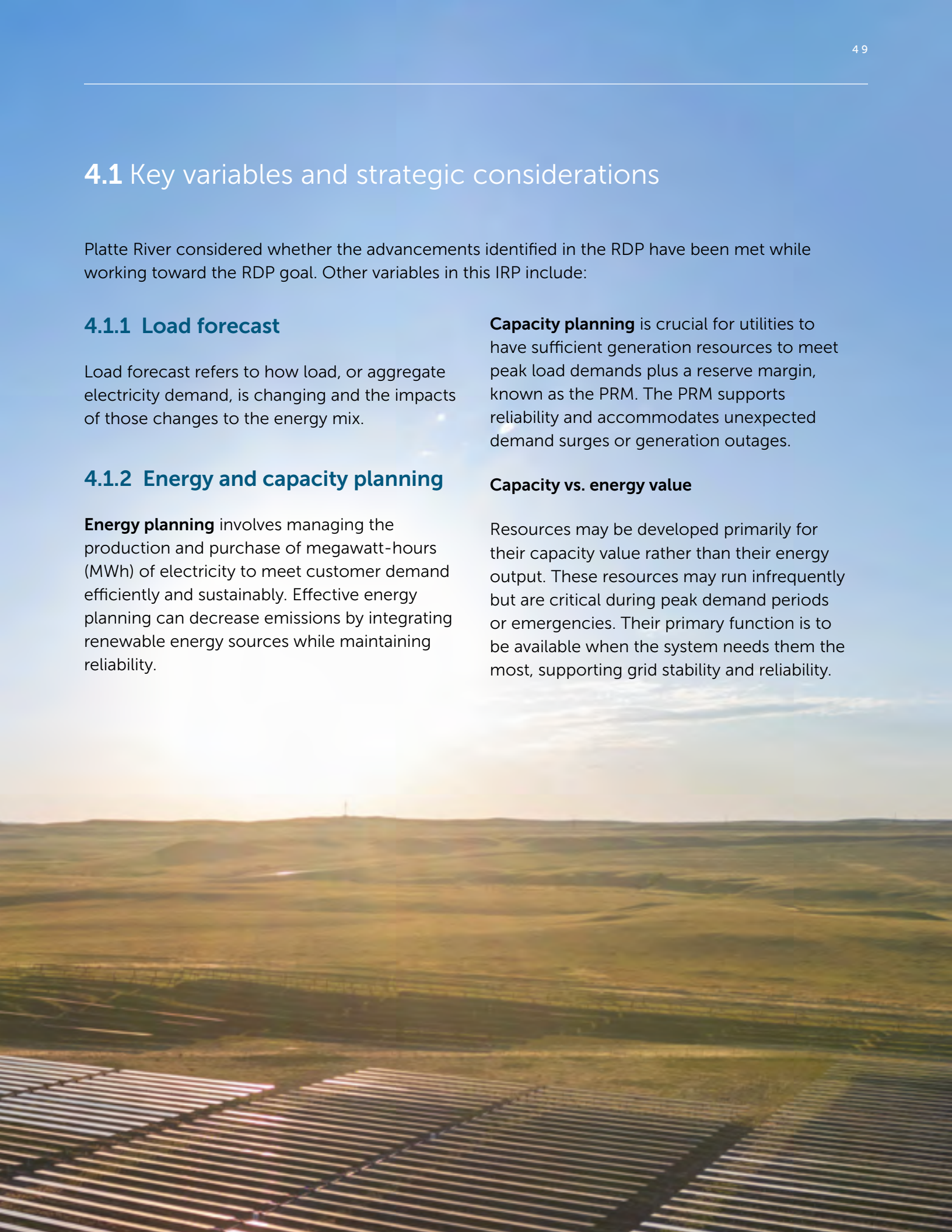
## 4.1.2 Energy and capacity planning

**Energy planning** involves managing the production and purchase of megawatt-hours (MWh) of electricity to meet customer demand efficiently and sustainably. Effective energy planning can decrease emissions by integrating renewable energy sources while maintaining reliability.

**Capacity planning** is crucial for utilities to have sufficient generation resources to meet peak load demands plus a reserve margin, known as the PRM. The PRM supports reliability and accommodates unexpected demand surges or generation outages.

**Capacity vs. energy value**

Resources may be developed primarily for their capacity value rather than their energy output. These resources may run infrequently but are critical during peak demand periods or emergencies. Their primary function is to be available when the system needs them the most, supporting grid stability and reliability.



### 4.1.3 Customer programs

Customer programs is the term to describe how existing energy efficiency programs are performing today, how they will evolve tomorrow, and how the behaviors that result from program adoption will impact load forecast.

Most of Platte River's existing customer programs are geared toward energy efficiency, access to renewable energy, support for low-income residents or electrification. Our IRP accounts for these programs' impact on total demand and peak demand for electricity.

The IRP also anticipates an increased focus on energy efficiency, battery storage and electrification. These needs will draw on existing customer programs and will be enhanced by new or expanded programs over the next several years.

### 4.1.4 Emerging technologies

Resource planning staff engaged with an engineering consulting team to evaluate the viability, long-term scalability and technological performance of emerging technologies. Platte River must balance the adoption of these technologies with the impacts they may have on the three foundational pillars.

### 4.1.5 Power markets

Participation in an organized market is needed for Platte River to achieve the clean energy transition. Over the years, Platte River has participated in numerous forums related to organized markets. Platte River, along with Xcel Energy, Black Hills Energy and later Colorado Springs Utilities, participated in the JDA for several years. The JDA was a small-scale, regionally focused market operated by Xcel Energy that allowed for more efficient use of generating resources and balancing renewable resources.

Although the JDA benefited Platte River, the opportunity to join an energy imbalance market was the next step in the path toward full energy market participation. This led to three of the JDA participants joining the SPP WEIS market in April 2023. While it functions like the JDA, the WEIS has a larger footprint and SPP serves as the independent market operator.

In September 2023, Platte River announced plans to join the SPP RTO West. Platte River, along with other utilities, expects to transition into this market on April 1, 2026. When the RTO West market is functioning, Platte River will sell all its generation into the market and purchase all its load obligations from the market.

### 4.1.6 Resource adequacy

Resource adequacy refers to the ability of Platte River to have sufficient resources to constantly deliver electricity to all consumers, even under challenging conditions. Resource adequacy is a critical aspect of resource planning and operation, to maintain enough generation capacity to meet the peak demand plus a reserve margin for unforeseen events, such as generator failures, weather events, sudden spikes in demand or other system disruptions.

### 4.1.7 Transmission and distribution infrastructure

As Platte River's energy portfolio continues to diversify, new resources will be interconnected to the transmission network. In a regional transmission network owned by more than one entity, the new resources may be interconnected directly to Platte River's transmission lines or to transmission lines owned by others.

Each transmission line owner manages a generator interconnection process to require the new generation resources to be interconnected in a way that does not adversely impact the reliability of the transmission network. New generation resources will require new interconnection infrastructure and if necessary, transmission network upgrades. The transmission network upgrades will be identified during the interconnect study process. The upgrades may include new transmission lines or modifying existing transmission lines.

As new resource projects are established, network upgrades or modifications will be evaluated and identified. Platte River has included the costs to fund future transmission projects in our long-term capital budget. Current budget estimates will be refined as the details of the new resources are identified.

### 4.1.8 DER adoption and integration

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DERs, today's customer demand must also include a seamless and economic integration of distributed resources.





## 4.2 Navigating challenges and maintaining the foundational pillars

The foundational pillars serve as guideposts for all Platte River activities, including the resource planning and modeling activities documented in this IRP.

### 4.2.1 Reliability – dispatchable capacity

Dispatchable capacity refers to any resource that can start, stop, and change output level quickly to produce more or less power when needed. The reliability challenges during extreme weather events and dark calms (characterized by the absence of solar and wind energy due to adverse weather conditions for multiple days) highlight the vulnerability of serving load with weather-dependent energy sources. These events underscore the critical role of dispatchable capacity in maintaining power supply.

Platte River commissioned a study with ACES to analyze different weather patterns from the past five decades across a broad region to understand the frequency and impact of extreme weather and dark calm events. The findings emphasize the need for a diversified energy portfolio and supply strategies that can withstand varying weather conditions, including rare and extreme events.

The future of energy reliability hinges on supporting renewable resources with dispatchable resources (including innovative energy storage solutions) to provide continuous power supply during all weather scenarios.

### 4.2.2 Environmental responsibility – cost of carbon

The portfolios modeled in this IRP assume that future electricity prices will also include carbon taxes.

The carbon-imposed cost portfolio imposes additional costs disincentivizing dispatch of high-carbon energy sources unless needed to maintain reliability of the system even after accounting for their environmental impact. This factors environmental ramifications of carbon emissions into decision-making, steering energy strategies toward more sustainable pathways.

The evaluation process for including technologies in a carbon-imposed cost portfolio prioritizes renewable energy sources like wind and solar due to their minimal carbon footprint. Dispatchable capacity resources are also considered for their potential to balance reliability with reduced emissions, aligning the portfolio with environmentally responsible objectives.



## 4.2.3 Financial sustainability – rates and affordability

As a not-for-profit utility, Platte River's revenues from its wholesale power rates fund ongoing operations and are reinvested into the system for the benefit of the owner communities. The owner communities' distribution utilities integrate Platte River's wholesale rates into their retail and commercial electric rates.

Platte River's rate-setting policy calls for established service offerings and supporting rate structures that complement the strategic objectives and values of the organization. Platte River's rate structure strives to meet the following objectives:

- Align wholesale pricing signals with cost of service
- Adapt to cost structure changes
- Integrate noncarbon resource additions

In support of Platte River's foundational pillars of providing reliable, environmentally responsible and financially sustainable energy and services, and Platte River's mission, vision and values and strategic initiatives, the strategic financial plan provides direction to preserve long-term financial sustainability and manage financial risk. The objectives of the strategic financial plan are:

- Generate adequate earnings margins and cash flows



- Maintain sufficient liquidity for operational stability
- Maintain access to low-cost capital
- Provide wholesale rate stability
- Maximize cost savings through pricing signals that provide system benefits and revenue stability
- Navigate resource acquisition costs increases and delays

Platte River is also subject to financial and rate requirements in the Power Supply Agreements and the General Power Bond Resolution. Platte River's Board of Directors has the exclusive authority to establish electric rates and must review rates at least once each calendar year.

To meet these objectives and requirements, staff established financial metrics and rate stability strategies, taking into consideration rating agency guidelines. Following its strategic financial plan, Platte River will maintain long-term financial sustainability by implementing appropriate rates and strategies that:

- Reduce significant single-year rate hikes
- Provide greater rate predictability to support owner communities with more accurate, long-term planning
- Maintain a strong financial position and AA credit rating

Competitive wholesale rates give the owner communities economic benefits for their customers. Platte River strives to maintain services and rates offered at competitive prices compared to similar services and products provided by other wholesale electric utilities in the region. Platte River's fiscal responsibility and rate stability strategies help reduce long-term rate pressure and give the owner communities greater rate predictability.

Platte River's long-term rate forecast is prepared and presented to the board of directors in the spring of each year. The IRP results, along with the most current assumptions, will be included in the rate forecast prepared in spring 2024.



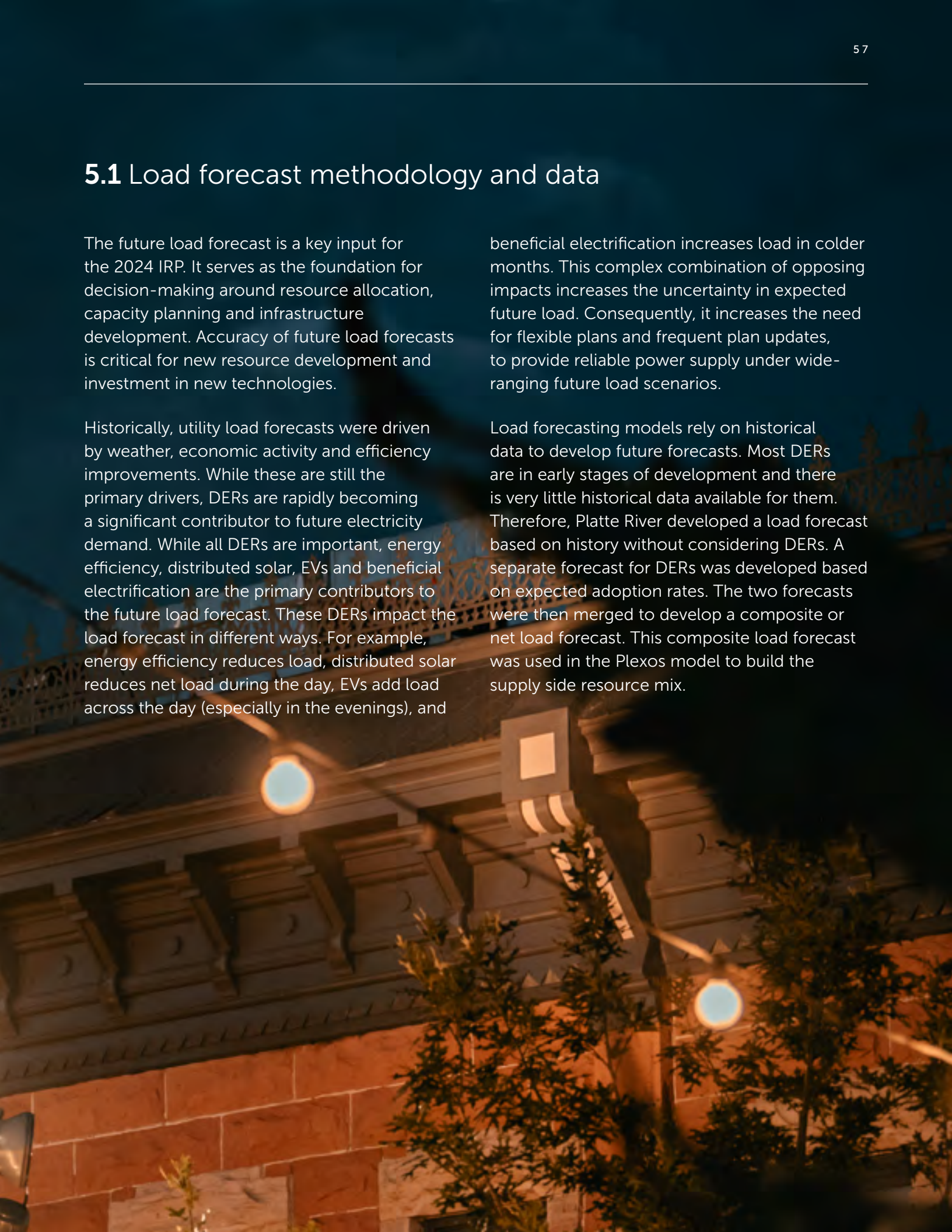

# 05 Electricity demand

# **5.1** Load forecast methodology and data

The future load forecast is a key input for the 2024 IRP. It serves as the foundation for decision-making around resource allocation, capacity planning and infrastructure development. Accuracy of future load forecasts is critical for new resource development and investment in new technologies.

Historically, utility load forecasts were driven by weather, economic activity and efficiency improvements. While these are still the primary drivers, DERs are rapidly becoming a significant contributor to future electricity demand. While all DERs are important, energy efficiency, distributed solar, EVs and beneficial electrification are the primary contributors to the future load forecast. These DERs impact the load forecast in different ways. For example, energy efficiency reduces load, distributed solar reduces net load during the day, EVs add load across the day (especially in the evenings), and beneficial electrification increases load in colder months. This complex combination of opposing impacts increases the uncertainty in expected future load. Consequently, it increases the need for flexible plans and frequent plan updates, to provide reliable power supply under wide-ranging future load scenarios.

Load forecasting models rely on historical data to develop future forecasts. Most DERs are in early stages of development and there is very little historical data available for them. Therefore, Platte River developed a load forecast based on history without considering DERs. A separate forecast for DERs was developed based on expected adoption rates. The two forecasts were then merged to develop a composite or net load forecast. This composite load forecast was used in the Plexos model to build the supply side resource mix.



# 5.2 Load forecast without DER

Platte River hired The Energy Authority (TEA), a third-party consultant, to develop a 20-year load forecast for the planning period of 2024-2043. TEA developed a load forecast without considering DERs, referred to as the base load forecast. TEA developed a forecast of monthly energy consumption and monthly peak demand as well as hourly load shapes.

## 5.2.1 Methodology

The monthly load forecast used a "least squares linear regression" model, using historical data to derive a linear relationship between a dependent variable and one or more independent variables. The dependent variable was forecasted using linear relationships and projections for each independent variable as discussed below.

Forty years of historical weather data, along with 20 years of load and economic data, were used to train three linear regression models. The first model considered total monthly energy as the regression's dependent variable. The remaining two models considered peak load as the dependent variable, with a model specifically for June through September and another for all remaining months in the year. This split was due to the contrast in peak load history between summer, which has grown consistently, and winter, which has seen a slight decrease since the late 2000s. Figure 7 illustrates the total and peak load history for Platte River, aggregated by year.

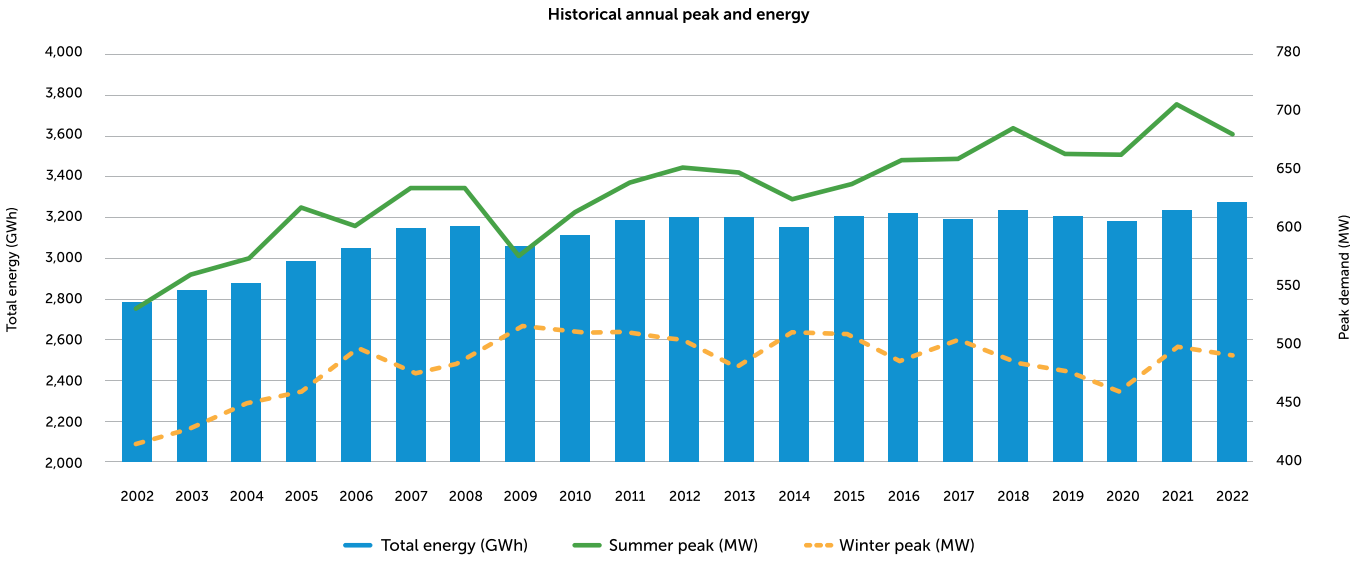



**Figure 7.** *Historical annual peak and energy*

Once the regression model was trained using historical data, a projection for each of the forecast drivers was input into the three models, creating monthly forecasts for total energy and peak load.

## 5.2.2 Forecast drivers

Future load growth can be driven by weather trends, economic factors or specific changes in customer usage patterns. To project future load patterns, Platte River's linear regression model used temperature, number of households and changes in air conditioning use.

**Weather and seasonal impacts.** One of the fundamental metrics to quantify the severity of weather is degree days. This metric takes the difference between the average daily temperature and a set point. In this case, the set point was 65 degrees Fahrenheit (˚F). Heating degree days take the sum of this calculation for temperatures below 65˚F, while cooling degree days use this calculation for temperatures above 65˚F. The distinction between heating and cooling degree days was made because hot and cold weather have different impacts on customer energy usage.

Based on the past 40 years of historical temperature data, a weather-normal forecast was developed for both heating and cooling degree days. Forty years of data were used to better capture the slight warming trend that has been observed in temperature history. This warming trend was incorporated into the weather-normalized forecast, resulting in a slight decrease in annual heating degree days and a slight increase in annual cooling degree days over time, as illustrated in Figure 8.

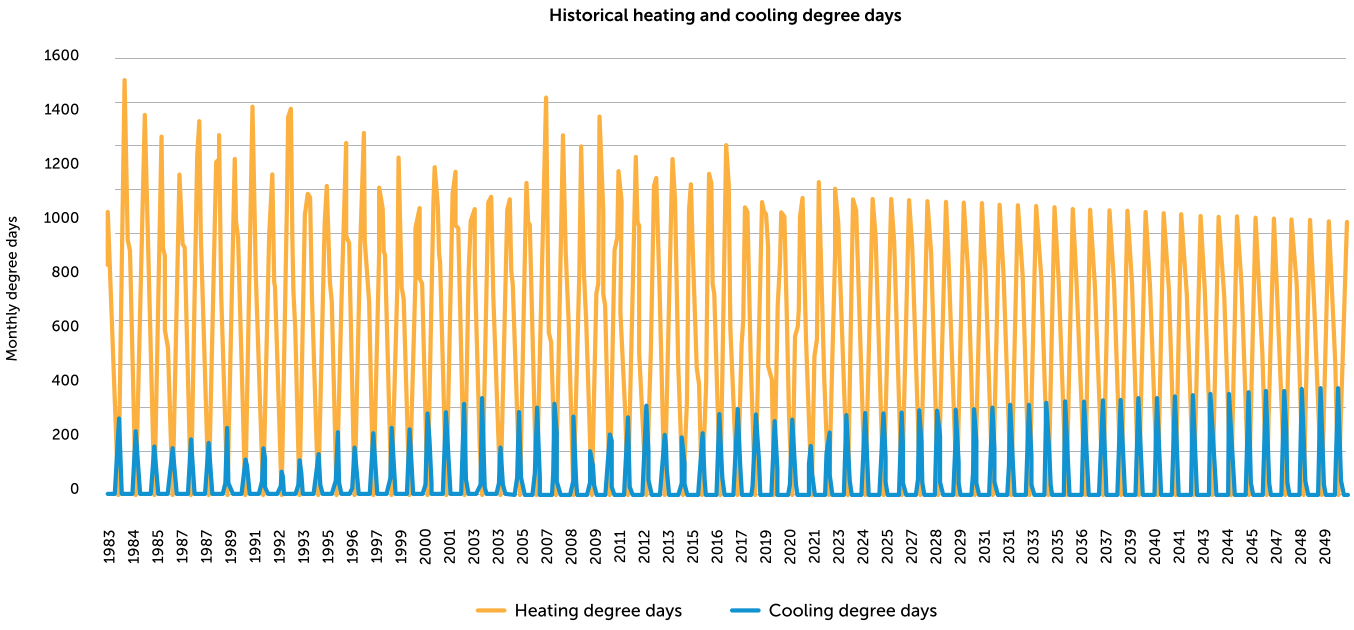



**Figure 8.** *Historical heating and cooling degree days*

Another factor incorporated into the load forecast model was the month of the year. This was used both to smooth the monthly forecast and to better consider seasonal impacts that may not be captured solely using heating or cooling degree days.

**Number of households.** Number of households was used to project economic growth within Platte River's service territory. These projections were obtained for Larimer County from Woods and Poole, an economic forecasting firm. While sections of Platte River's service territory exist in surrounding counties, the model assumes that economic growth in Larimer County reflects the growth of nearby areas as well. Growth in number of households is expected to continue to soften through the 2030s, following the trend observed since 2011. From 2040 onward, growth in number of households slightly flattens as illustrated in Figure 9.

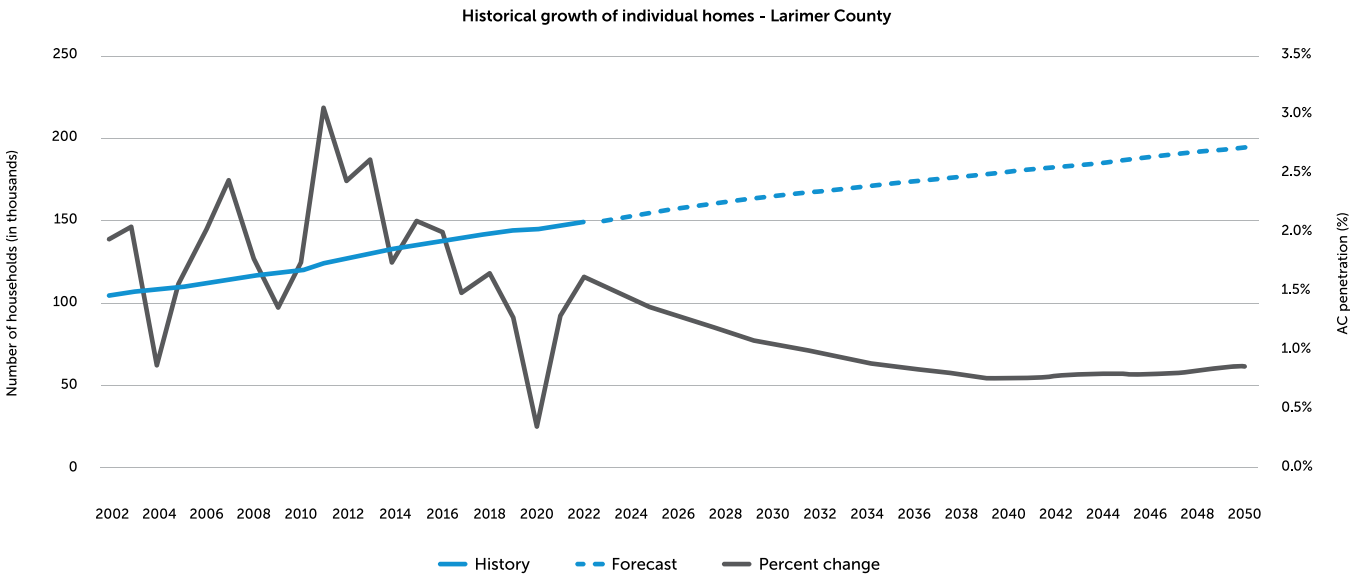



**Figure 9.** *Historical growth of individual homes*

**Air conditioning use.** A large driver for load growth over the past 20 years is an increase in the percentage of single-family homes with central air conditioning. This has increased both total energy consumption and peak demand during the summer months. Growth in air conditioner use is expected to slightly decrease in the future, with an average of 0.6% year-over-year increase through 2050, as illustrated in Figure 10.

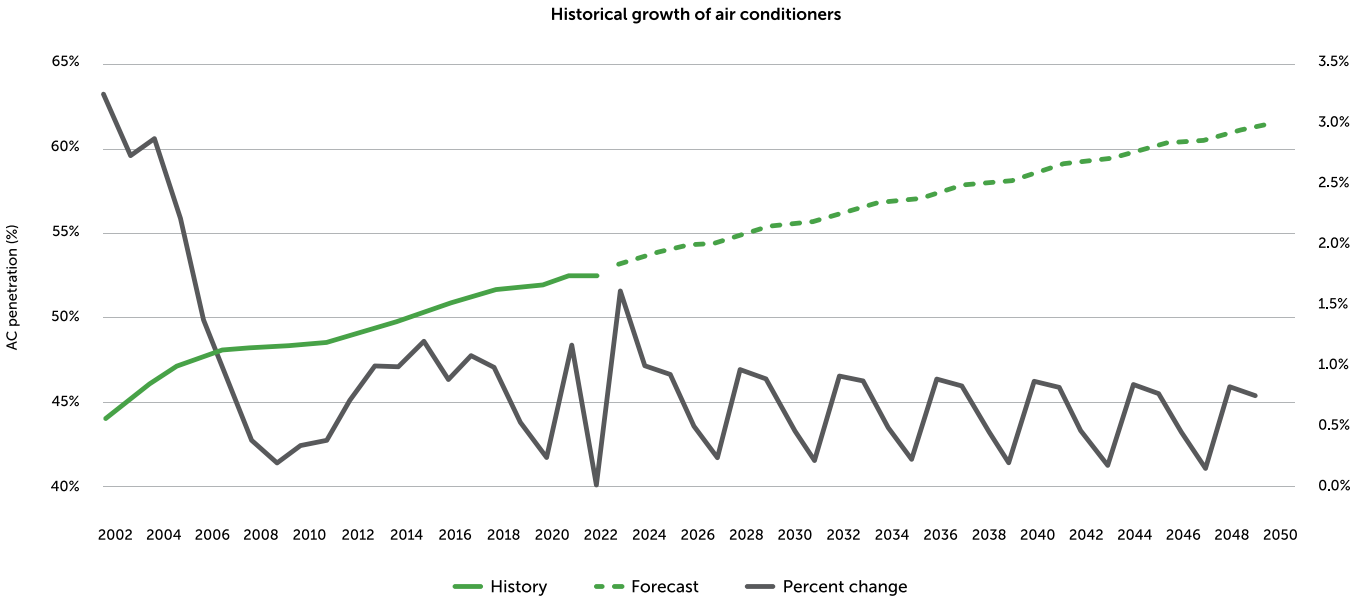



**Figure 10.** *Historical growth of air conditioners*

## 5.2.3 Forecast results

Figure 11 displays the annual total energy forecast, summer peak demand and winter peak demand through 2050. The growth in summer peak demand is expected to outpace growth in total energy, reflecting the trend observed since the early 2010s. While winter peak demand is projected to increase, it is at a lower rate than both summer peak and total energy forecasts. Average summer peak and total energy growth rates for the first 10 years of the plan are shown in Table 3.

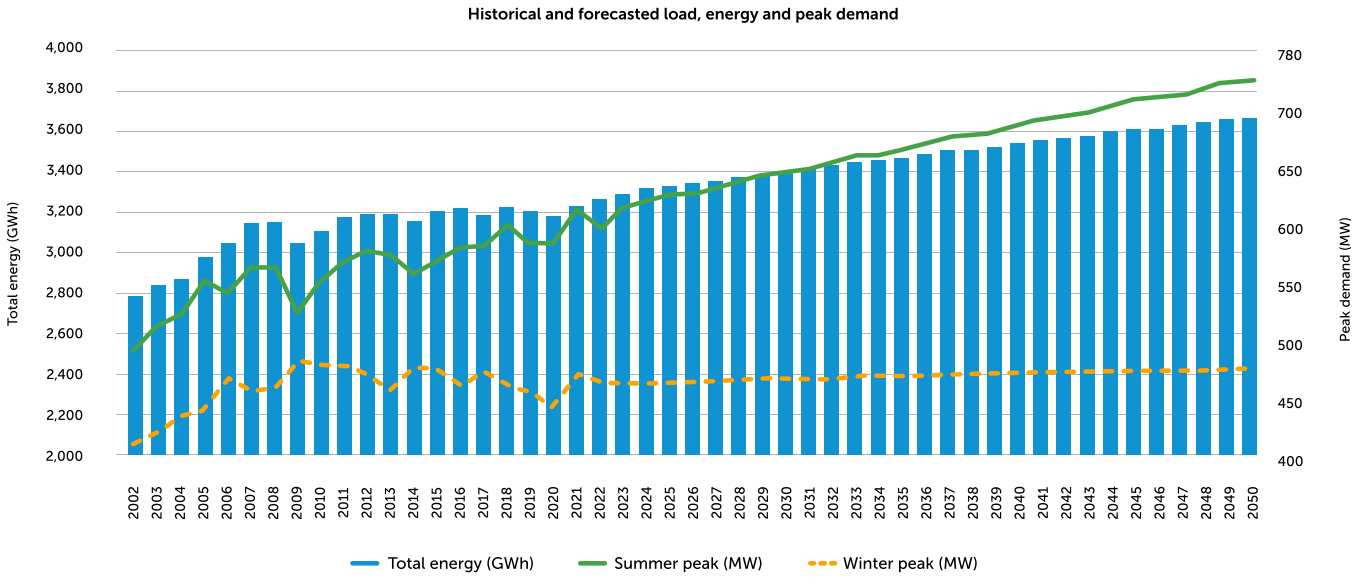



**Figure 11.** *Historical and forecasted load, energy and peak demand (base forecast without DERs)*

| 2024 – 2033 year-over-year average growth – base load forecast | |
|---|---|
| Total energy | 0.5% |
| Summer peak load | 0.8% |

**Table 3.** *Average annual load growth, energy and peak demand*

## 5.2.4 Hourly load shape

In addition to monthly forecasts, an hourly load shape forecast was developed for hourly dispatch modeling purposes. Rather than using a linear regression tool, a more robust model was chosen to develop the hourly shape due to the many nuances observed between hourly load and temperature changes over time. Hourly load data for 2013-2022 and temperature data for 2002-2022 was input into the model. The model created an hourly weather normal temperature forecast using the rank and average method. After the hourly load forecast for 2023 was developed, the total energy and peak load shape for each month was then normalized to the monthly projections for 2023. While there were not large discrepancies between the hourly and monthly model projections prior to normalization, this was done to ensure consistency between the two forecasts.

Figure 12 compares the average hourly shape, by month, for the 10 years of historical hourly data and the 2023 projections. There are increases in average hourly load between the load history and forecast, but these reflect load growth observed during 2013-2022. The forecasted load shape is commensurate with historical load shapes.

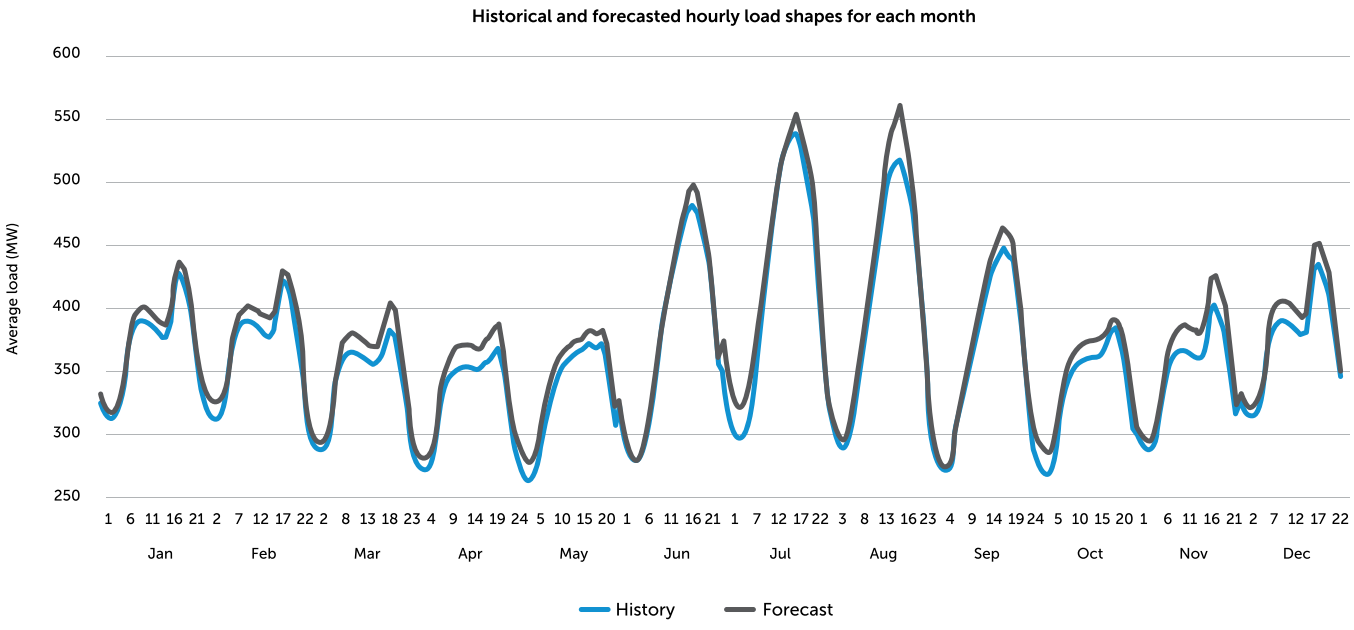



**Figure 12.** *Historical and forecasted hourly load shapes for each month*

## 5.3 DER integration, flexible DERs and the virtual power plant

The term "DER" encompasses a range of technologies installed and used at a customer's premises or within the distribution system. DER can be either on the customer or utility side of the meter. These assets potentially provide advantages to both the electric system and customers alike. These resources include energy efficiency, building electrification, transportation electrification, distributed generation, distributed energy storage and demand response.

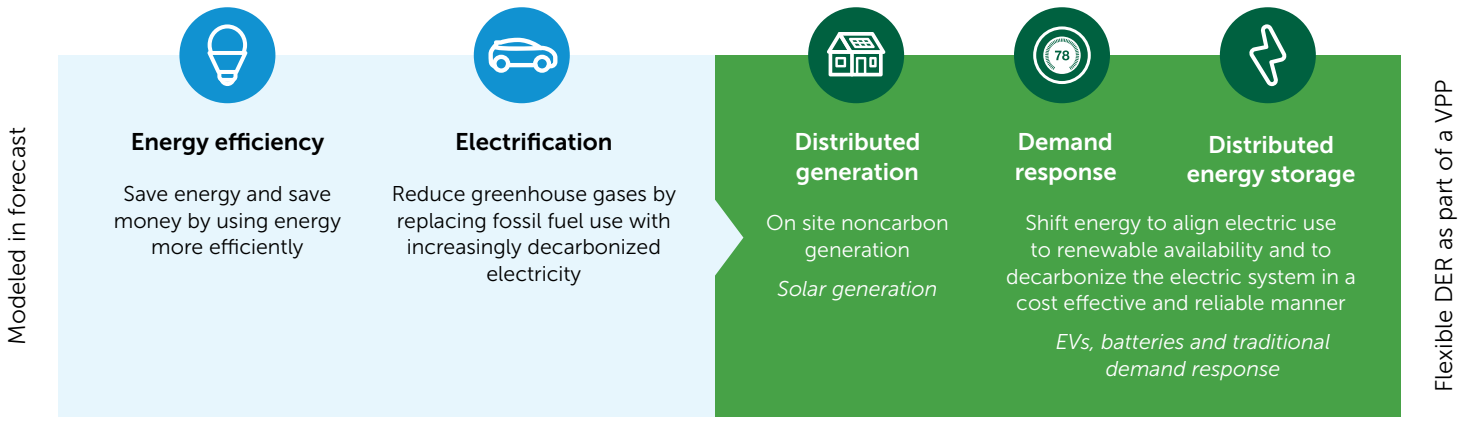
DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as "integrating" DERs. Integrating DERs means they have been made a functioning part of the electric system. This includes some or all of the following:

**Visibility and forecasting.** DERs must be "visible" to and predictable by electric system planners and operators for their effects to be taken into consideration. To support system planning, DER impacts must be forecast years in advance. To support system operations, DER forecasts must look seconds, minutes, or days into the future.

**Dispatchability or control.** Flexible DERs can be controlled or dispatched by utility system operators to maintain reliability or to achieve system-wide financial benefits.

**Customer awareness, engagement and participation.** The customer is provided support and services to help them understand their opportunities, benefits and responsibilities as participants in the electric system.

When flexible DERs are integrated in this manner and aggregated into coordinated operational programs, they are considered a virtual power plant (VPP). A VPP is a network of aggregated flexible DERs that can be controlled by Platte River and the owner community distribution utilities through advanced software to support grid reliability and financial sustainability.



### 5.3.1 DER forecast studies

Platte River commissioned two DER forecast studies to support DER and resource planning. The first, Platte River Power Authority Beneficial Building Electrification Forecast, Mar. 12, 2022, was completed by Apex Analytics, LLC ("Building Electrification Study"). The second, Distributed Energy Resources Forecast and Potential Study, Aug. 28, 2023, was completed by Dunsky Energy+Climate Advisors ("DER Study").[9] A summary of the studies and their results is included below, and the full studies are available in the appendices of this report.

The Building Electrification Study scope included the following:

- Study period: 24 years (2023 through 2046)
- Building electrification categories: space heating, water heating and cooking
- Sectors/segments: residential and commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state and local codes, standards, or incentives) and program or utility factors and inputs (like incentives or rates)
- Outputs: annual energy impacts, hourly and peak demand impacts

The DER Study scope included the following:

- Study period: 20 years (2024 through 2043)



- DER categories: energy efficiency, transportation electrification, distributed generation + storage, and demand response (or flexible DER, including EV charge management, battery storage management and traditional demand response)
- Sectors/segments: residential single family, residential multi-family, small commercial, large commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state, and local codes, standards, or incentives) and program or utility factors and inputs (like incentives, rates, or avoided costs)

[9] Platte River did not consider cogeneration and district heating/cooling in these studies because of the lack of interest by our customers and the future trend of electrifying heating and cooling to reduce gas burning.



- Outputs: technology adoption (number of units), annual energy impacts, hourly and peak demand impacts, program metrics (budgets)

The results of these studies inform load forecasts and DER program plans as discussed below.

## 5.3.2 Energy efficiency

Energy efficiency programs help customers reduce their energy consumption through a variety of interventions, including outreach, education, contractor engagement and incentives. Platte River and the owner communities deliver energy efficiency programs under the Efficiency Works™ brand, jointly funded and administered by Platte River and its owner communities. These programs give communities a cost-effective way to manage load growth, reduce carbon emissions and help customers reduce electricity costs, and provide a cost-effective option when compared to the cost of supply-side resources otherwise needed.

### 5.3.2.1 Energy efficiency forecast study results

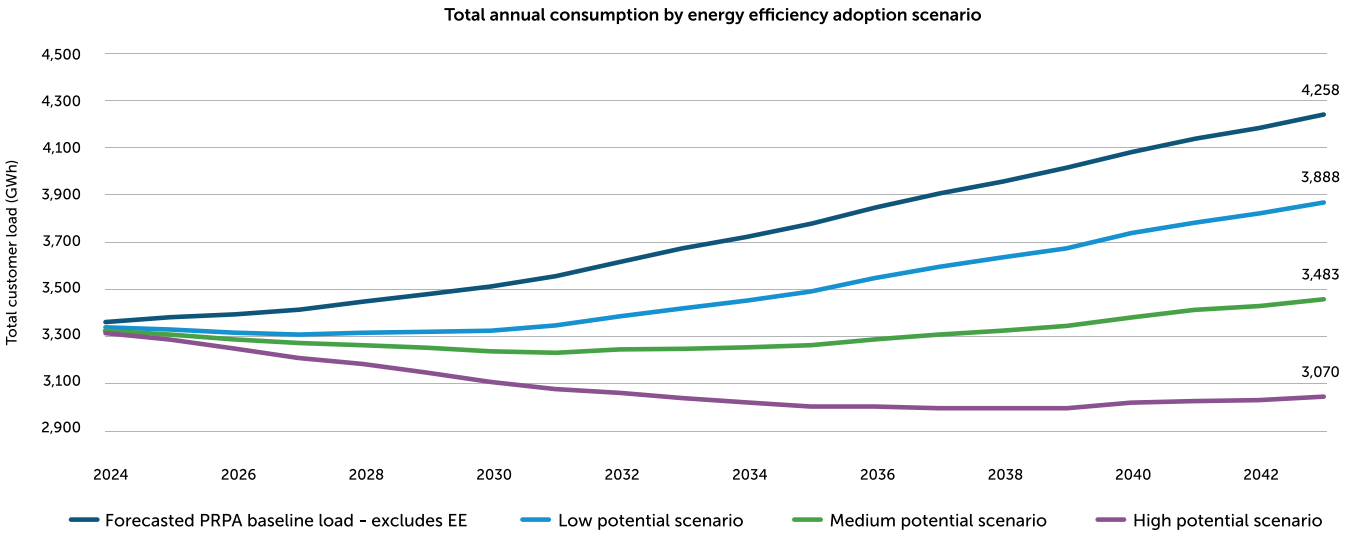
The DER Study evaluated the energy efficiency potential, identifying three adoption scenarios: low, medium and high. The adoption scenarios were evaluated based on three other utility potential studies, taking into consideration local factors, such as the owner communities' customer segmentation, historical participation

data for existing Platte River energy efficiency programs and the building electrification forecast study identifying heat pump adoption rates. Two of the key takeaways from the study include:

- Platte River could achieve an average incremental savings rate of almost 0.78% of annual load each year between 2024 and 2030 in the low scenario, 1.15% in the medium scenario, 1.71% in the high scenario. This would come at a cumulative cost (2024-2030) of about $105 million, $200 million and $460 million, respectively.

- Energy efficiency savings for lighting, heating, ventilation and air conditioning (HVAC) pumps and fans and plug load (energy used by equipment that is plugged into an outlet) make up over 60% of total forecasted savings by 2043 for the commercial sector. For the residential sector, heating provides almost 60% of the energy efficiency savings, due in part to growing residential heating electrification, followed by plug load and domestic hot water.

The study applied the energy efficiency potential scenarios to the estimated customer baseload forecast. Figure 13 shows the effect of energy efficiency on load forecast and Figure 14 shows energy savings by market segment.




Note: The baseline load includes expected customer load growth and electrification growth (PRPA baseline load + building electrification Low projection). Transportation electrification and distributed solar are not included in the baseline load.

**Figure 13.** *Total annual consumption by energy efficiency adoption scenario*

Platte River continues to invest significant resources in a portfolio of energy efficiency programs, which include some of the highest incentives in the region. These investments are intended to help avoid the need for new generation resources due to customers using energy more effectively.

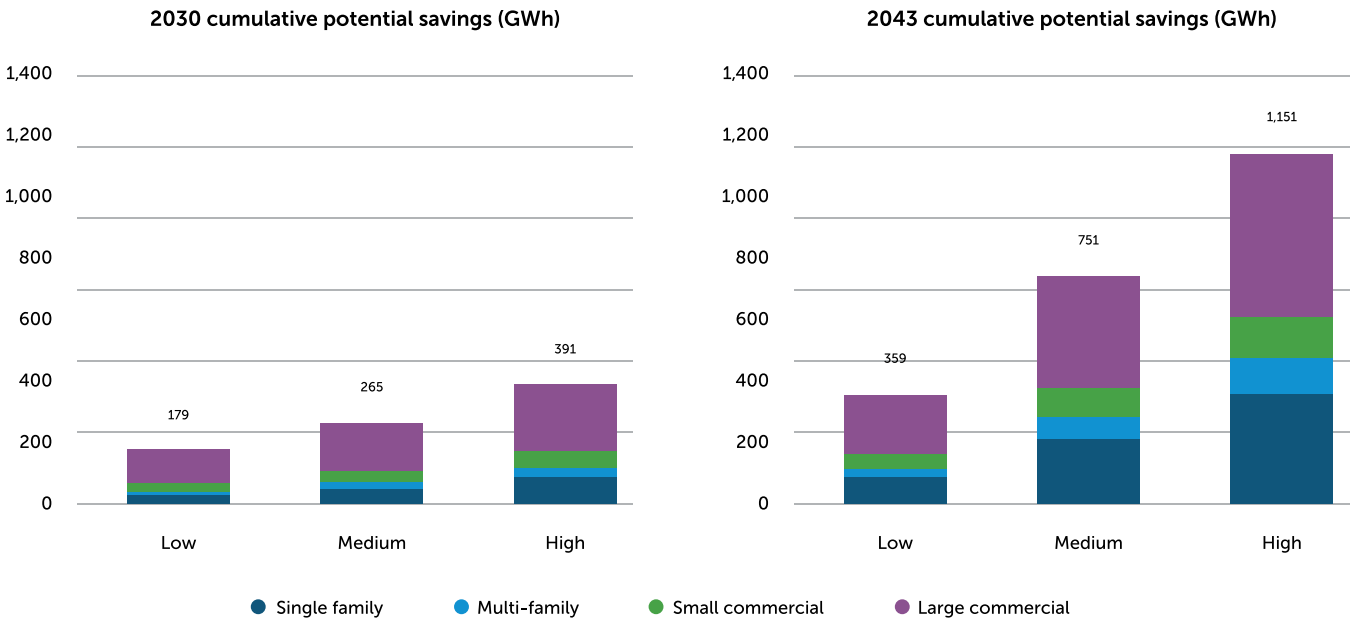



**Figure 14.** *Cumulative potential savings (GWh)*

However, current participation rates are consistent with the low forecast contained in the DER study. Platte River plans to continue investment in energy efficiency at current levels through 2030 and beyond with adjustment for inflation, as long as the investment provides value through customer participation and energy-saving benefits. See figures 15, 16 and 17 for estimated future investments and associated savings within the owner communities for energy efficiency services. These ongoing investments in energy efficiency services will continue to evolve and provide a strong foundation of programming for other DER technologies to build upon in future years.

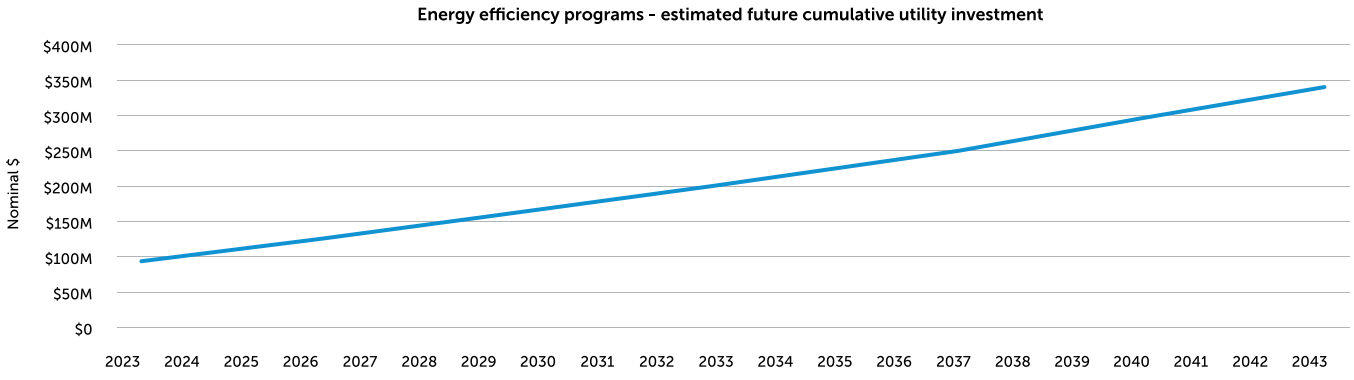



**Figure 15.** *Energy efficiency programs - estimated future cumulative utility investment*

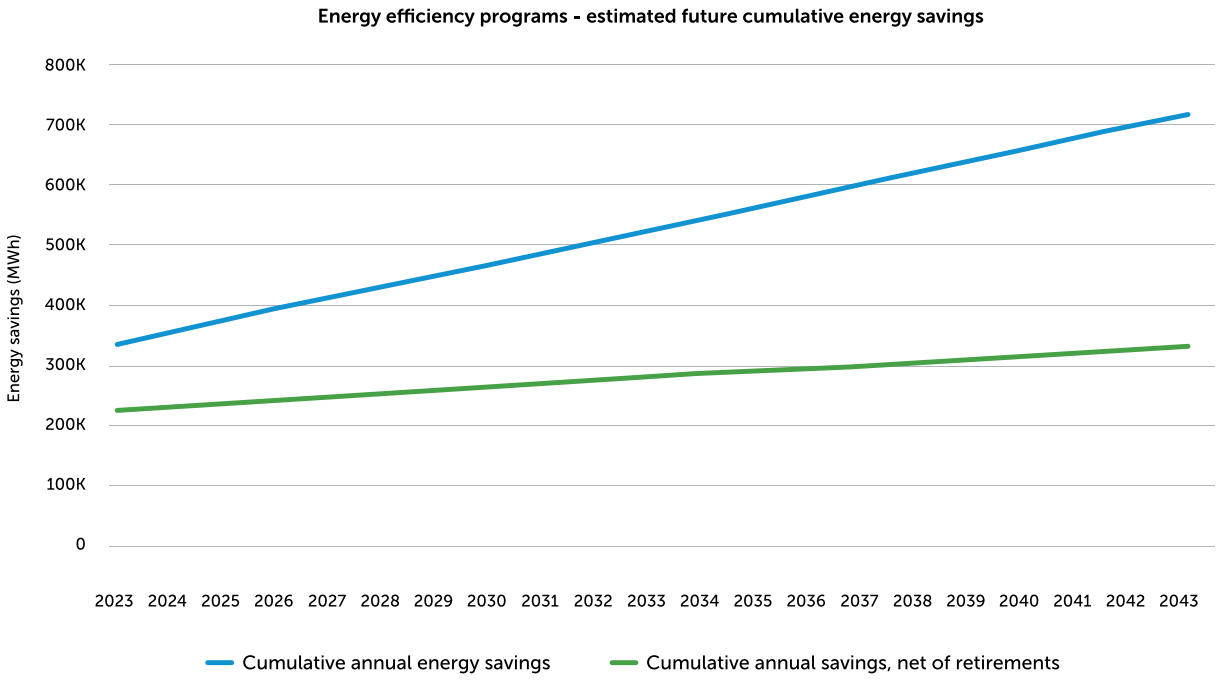



**Figure 16.** *Energy efficiency programs - estimated future cumulative energy savings*

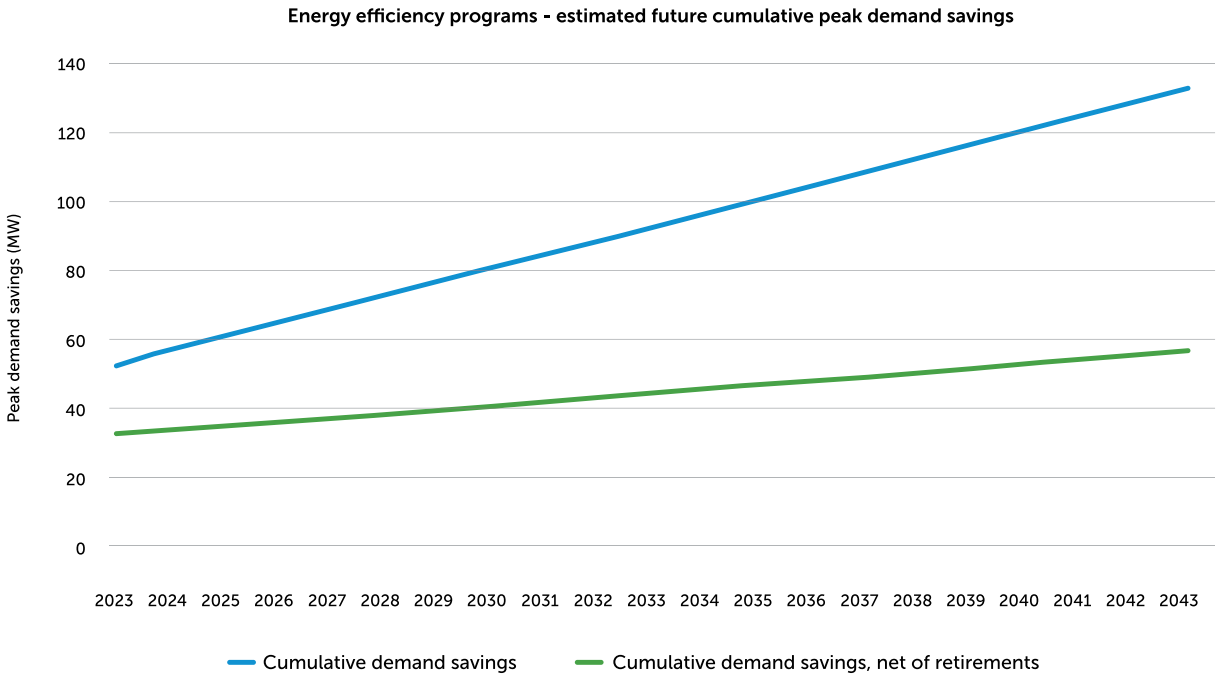



**Figure 17.** *Energy efficiency programs - estimated future cumulative peak demand savings*

## 5.3.3 Electrification

### 5.3.3.1 Buildings

Building electrification refers to new uses for electricity that replace other sources of energy used in buildings. When building electrification provides additional economic benefits, grid benefits and environmental benefits, it is referred to as beneficial building electrification. Typically, building electrification involves the replacement of natural gas or propane appliances in residential and commercial properties with more carbon-efficient appliances that consume electricity.

As Platte River's owner communities pursue carbon emission reduction and as Platte River decarbonizes its generation, building electrification becomes an attractive alternative that can be incorporated into existing Efficiency Works customer programs.

**Building electrification forecast study results.** In 2022, Platte River completed a Building Electrification Study to provide a range of forecasts for building electrification adoption and effects on electric consumption. The study evaluated the adoption electrification of end uses with a focus on those with the most significant potential: space heating, water heating and cooking. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions and technology types. Medium utility incentives were assumed for all three scenarios. Some key findings from the study include:

- Only minor impacts on overall electricity consumption are expected through 2030. However, starting in the 2030s, building electrification impacts become larger.
- Most of the energy and demand growth occurs in the winter; summer impacts are minimal.
- Full electrification of heating during extreme cold will cause Platte River to become a winter peaking utility sometime after 2035.
- Policies requiring all-electric new homes or businesses could push impacts sooner – winter peaking will occur within five to 10 years of requiring all-electric new homes.
- Electrifying residential space heating with heat pumps is the highest impact building electrification technology and supports ongoing energy efficiency options.
- Full electrification of heating causes significant cost and reliability challenges.
- Without program or policy support, or significant changes to heat pump technology, efficiency and economics, cost and accessibility challenges will limit adoption of building electrification.

Results of the study are shown in Figures 18 and 19. Additional details on building electrification impacts can be found in the APEX Analytics study at prpa.org/2024irp/information.

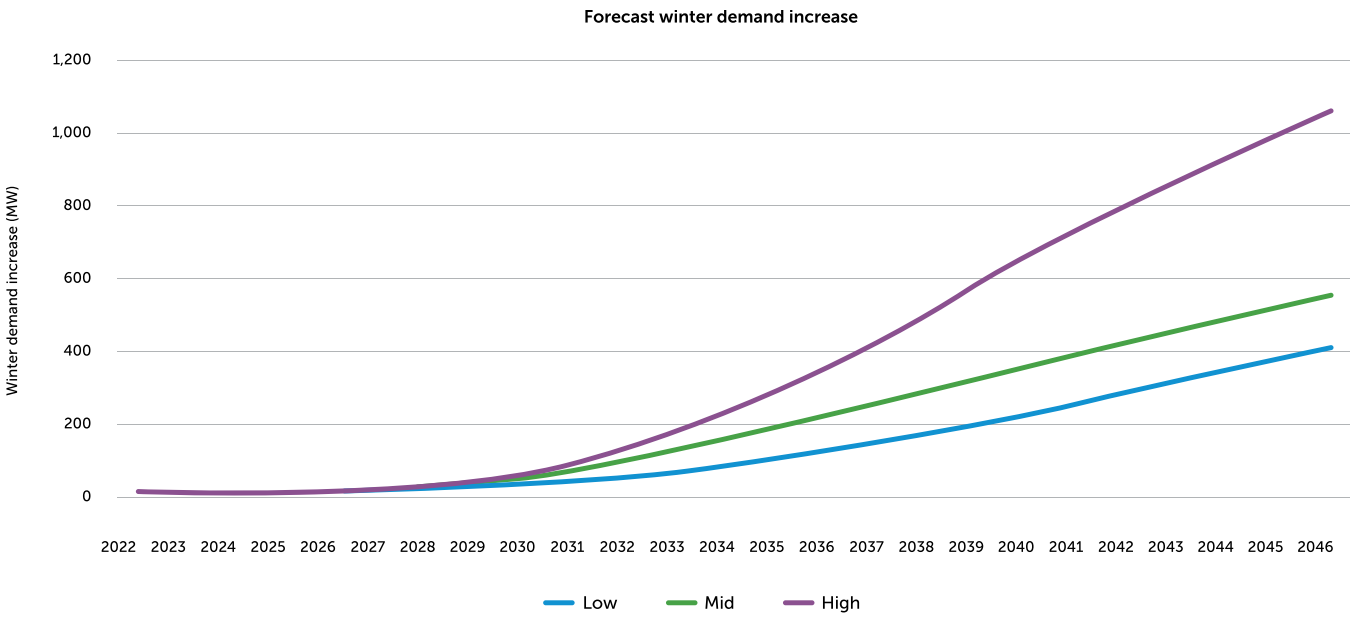



**Figure 18.** *Forecasted winter demand increase*

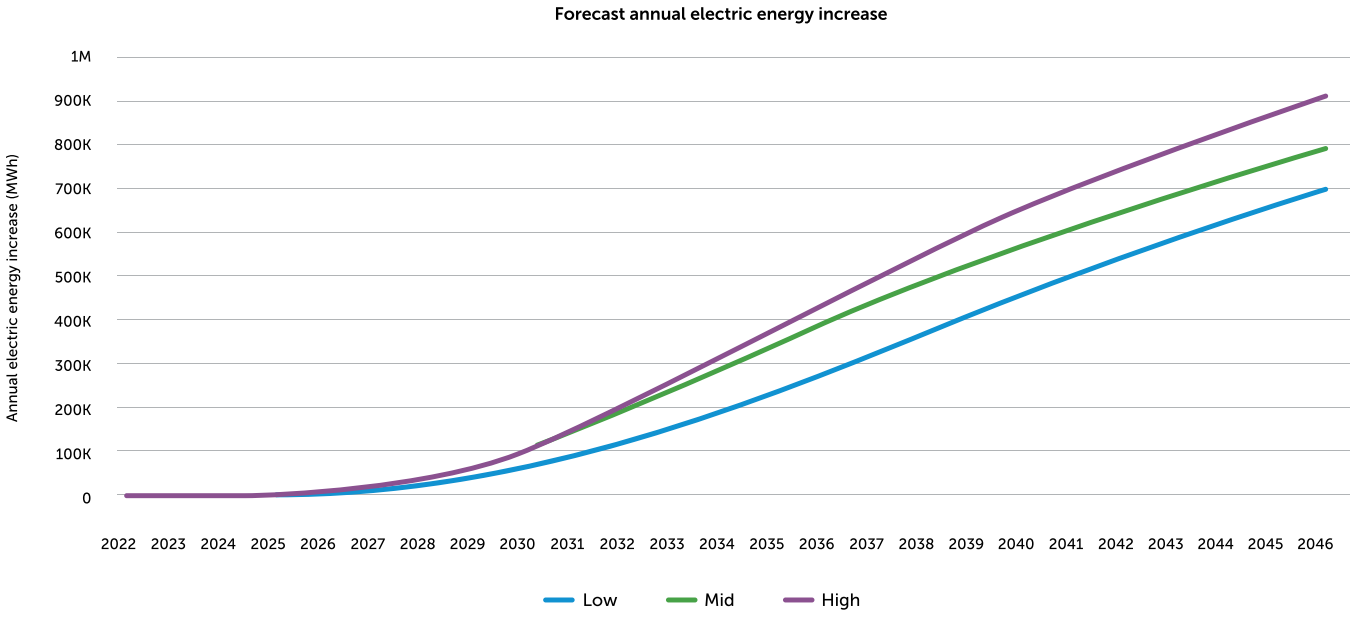



**Figure 19.** *Forecasted annual electric energy increase*

Platte River initially adopted the low forecast for its load forecast in 2022. However, it now appears the medium forecast best reflects recent changes observed in the market. These include increasing availability of federal and state tax incentives, along with the increasing acceptance of heat pump technology by local HVAC contractors.

### 5.3.3.2 Transportation

Transportation electrification refers to the shift from vehicles with internal combustion engines powered predominantly by fossil fuels (gasoline and diesel) to vehicles powered by batteries charged from the electric grid. Transportation electrification reduces dependence on fossil fuels and reduces emissions from burning fossil fuels, including greenhouse gases. Transportation electrification is driving challenges and opportunities for vehicle owners and operators; businesses involved in the sales, service and fueling of vehicles; and for electric utilities.

**Transportation electrification forecast study results.** The DER Study evaluated the adoption of EVs in the following categories: light-duty vehicles (including personal vehicles and commercial fleets), medium-duty-vehicles, heavy-duty vehicles and buses. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions; technology availability and cost declines; and market factors (for example, electric rates, fuel prices). Utility rebates were not evaluated. Table 4 summarizes the driving factors for each scenario considered in the study.



| Parameter | Low scenario | Medium scenario | High scenario |
|---|---|---|---|
| **Policy/program interventions** | | | |
| Public charging infrastructure expansion | Limited<br><br>Planned investments + current growth trajectory | Moderate<br><br>Planned investments + accelerated growth trajectory aligned with Colorado National EV Infrastructure Formula Program (NEVI[10]) | Significant<br><br>Expanded infrastructure to ensure adoption is not constrained |
| Vehicle incentives | Current federal and state EV incentives, phase out prematurely in 2028 and 2026, respectively | Current federal and state EV incentives, phased out as currently planned in 2032 and 2028, respectively | Increased incentives and extended beyond currently planned in 2035 and 2030, respectively |
| Existing building charging infrastructure retrofits | Limited<br>15% of multi-unit buildings with access to charging by 2035 | Moderate<br><br>40% of multi-unit buildings with access to charging by 2035 | Significant<br><br>90% of multi-unit buildings with access to charging by 2035 |
| Zero-emission vehicle mandates | None | None | Stringent<br><br>100% by 2035 |
| **Technology factors** | | | |
| Battery costs | Limited cost declines | Moderate cost declines | Aggressive cost declines |
| EV model availability | Limited availability | Moderate availability | High availability |
| **Market factors** | | | |
| Vehicle sale | | Maintain historical trends | |
| Fuel prices | Limited escalation | Moderate escalation | Rapid escalation |

**Table 4.** *Primary drivers for transportation electrification*

Figures 20, 21 and 22 depict the anticipated adoption for the three scenarios in terms of number of vehicles, annual energy and summer peak demand.

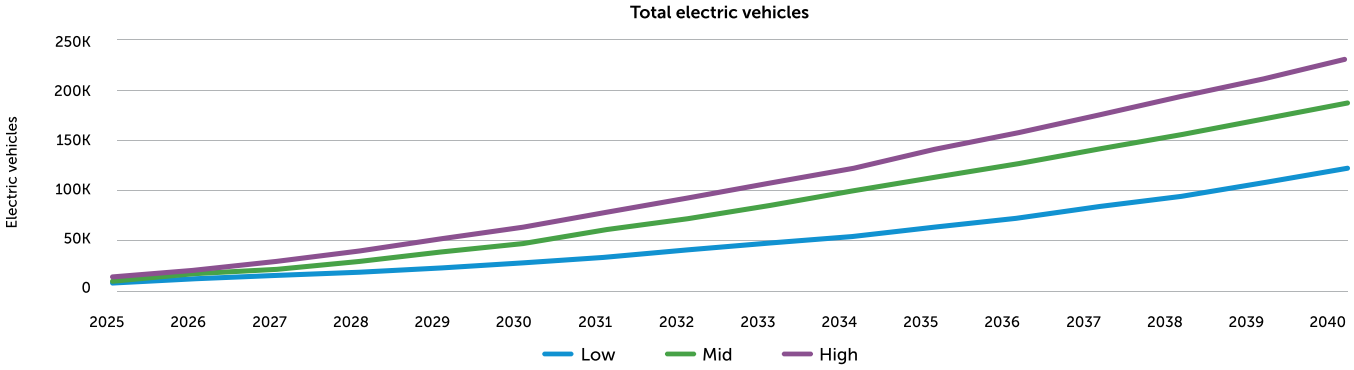



**Figure 20.** *Total electric vehicles*

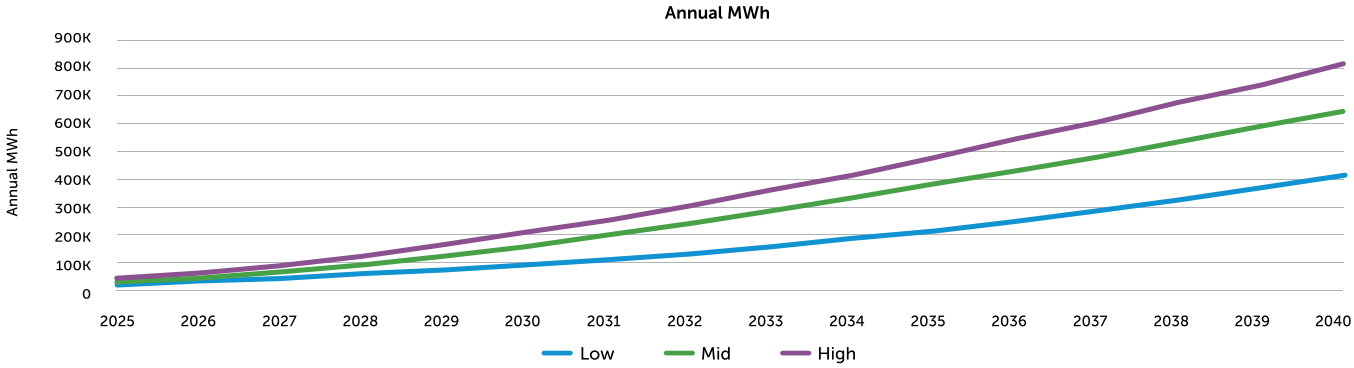



**Figure 21.** *Annual MWh*

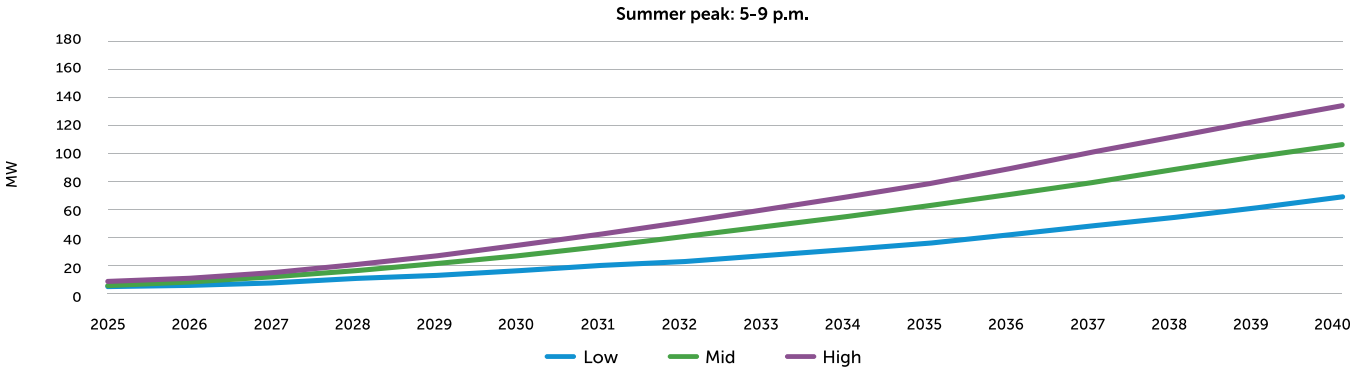



**Figure 22.** *Summer peak: 5-9 p.m.*

[10] National Electric Vehicle Infrastructure Formula Program (NEVI) is a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors.



Note that the summer peak demands are based on a diverse set of EV charging profiles (home charging, workplace charging, public charging, commercial fleet charging). These profiles assume some customers will respond to time-of-use pricing, where available. Winter peak demand effects are expected to be about 70% higher than summer peak due to the additional use of electricity in EVs to provide heat in the occupant compartment and to the batteries.

In all three growth scenarios the forecasted growth in EV adoption is poised to escalate significantly during the study period of 2023-2043.

**Monitoring and forecasting EV adoption.** As of the end of 2022, Platte River's owner communities witnessed a notable surge in the adoption of EVs. The number of estimated registered EVs within the communities at the end of 2022 was around 2,900. Throughout 2023 EV adoption has seen a steady increase, with an estimated 4,000 EVs by the end of the year, slightly under the previous forecast of 4,500. This growth within the owner communities follows closely with the Colorado state trend of a 3% growth each month, or 43% annually, in new EV registration.

The DER Study evaluated a range of adoption scenarios to inform the load forecast used for resource planning. Platte River has chosen the medium forecast, approximately 48,000 EVs by the end of 2030, which represents 42% compound annual growth from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

### 5.3.4 Transitioning Efficiency Works programs to distributed energy solutions

The Efficiency Works program offerings through Platte River's distributed energy solutions department are shifting focus to meet the customer needs through additional product education,

energy advisory services and repurposing incentives to business and home upgrades that support future load flexibility. A few examples of this transition include:

- Supporting building electrification upgrades that can provide future flexibility or load control throughout the year (not just a summer peak reduction of air conditioner loads).
- Incentivizing public EV charger infrastructure to provide more charging locations for EV drivers throughout the day to accommodate different charge control program models.
- Optimizing commercial HVAC equipment though the Building Tune-up program that will provide an eventual path for advanced system automation control installations and ongoing system performance visibility.

A variety of new customer program offerings have been developed and launched in recent years to support this transition as described in sections below.

## 5.3.5 New customer programs to address future electrification requirements

### 5.3.5.1 Building electrification activities

In 2023, the Efficiency Works programs continued to support owner community initiatives and began shifting to include multiple building electrification measures. These measures mostly focused on heating and cooling equipment within residential properties while leveraging the existing energy efficiency contractor networks. The initial building electrification programming is focused on the following areas to support customers as they decarbonize their homes and business:

- Retrofitting existing residential properties
- Educating residential and commercial customers on effective ways to use their energy with building electrification upgrades
- Providing incentives to the income qualified community sector to support building electrification initiatives
- Developing programs to support distributors selling building electrification equipment in the commercial HVAC sector
- Engaging and training local contractors about the benefits of building electrification upgrades

The shift in building electrification programming also aligns with possible incentives offered through the Inflation Reduction Act and state tax credits. As interest in building electrification continues to grow, customer programs will encourage energy efficiency upgrades like building envelope improvements. In combination with the building electrification upgrades, these improvements will allow for the potential to call on demand response activities for longer durations in the future.

# Including income-qualified communities in the energy transition

For several years, Platte River has offered various programs to support income-qualified customers. In 2021, the Efficiency Works Business team launched the **Community Efficiency Grant** to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community. This effort has increased the number of participating entities **eight-fold** on an annual basis, resulting in 103 upgrades, saving an estimated $385,000 annually on the businesses' electric costs through the investment of nearly $2.1 million of the Efficiency Work Business programs. The Community Efficiency Grant is expanding eligibility in 2024 to more entities that serve the community.

In addition, Efficiency Works has partnered with Energy Outreach Colorado (EOC) since 2016 to provide free energy advising and upgrades to eligible participants. In 2023, Efficiency Works revamped the partnership structure and services available, resulting in significant positive impacts for the residential income-qualified segment. The offerings have shifted focus to actively engage with participants on more significant home upgrades including energy efficiency and building electrification. According to the EOC, this partnership has grown to be one of the most well-funded income-qualified programs and has the strongest participation impact goals in the state of Colorado. In 2023, investments of nearly $1 million have been made to support the income-qualified residential upgrades in our communities and this level of annual investment is expected to continue.





### 5.3.5.2 Transportation electrification activities

Platte River supports customers on their transportation electrification journey as they evaluate options and consider adopting EVs. This support starts with information. Platte River and the owner communities offer information on EVs through Efficiency Works.

In 2022, Platte River launched an interactive EV shopper guide website. The website includes information on currently available EVs, including cost, performance specifications and available incentives. It also includes a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles. In 2023, the website was expanded to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions. In 2024, expansion in the EV space will continue to support commercial customers with additional technical services to plan for EV fleet transitions and work closely with the distribution utilities on potential service upgrades and interconnection requirements.

Platte River's commitment to advancing EV infrastructure is exemplified by the 2023 initiative offering one of the highest incentives in Colorado - $5,000 per public charging port. This incentive aims to encourage local businesses and multifamily properties to host public chargers by offsetting some of the installation cost. Promoting more public charging options and making EV charging more available and visible are intended to reduce "range anxiety" among EV drivers and potential EV drivers.

#### 5.3.5.3 Commercial HVAC system optimization activities

In 2021, Efficiency Works relaunched an improved Building Tune-up program focusing on supporting commercial customers to optimize more complex systems. The program is one of the few in the nation that focuses on upgrades and services ranging from enhanced maintenance practices to complex retrocommissioning. In its current form, the programming engages with large commercial and industrial customers to optimize complex building automation systems and local HVAC contractors performing ongoing maintenance services, and engages many small and medium commercial properties in the owner communities.

Since the relaunch, the program has increased energy savings at commercial properties from an annual average of four participants to over 50. The program has also increased the number of properties participating through increased engagement of local contractors in the HVAC industry. Program staff are currently evaluating options to expand services into monitoring-based commissioning and installing advanced rooftop unit controls during routine maintenance visits. Both expansion options will provide pathways for commercial customers to participate in a future VPP, providing additional energy consumption flexibility within the system.

### 5.3.6 Distributed generation and distributed energy storage

Distributed generation refers to electric generation sources, typically solar facilities, located near the point of use, within customer premises or on the distribution system. Similarly, distributed storage refers to energy storage, typically battery storage, located near the point of use, within customer premises or on the distribution system. Distributed generation and distributed storage are considered together in this section due to the synergy between them.

From Platte River's perspective, storage is essential to achieving a noncarbon electric system because it helps align variable renewable generation, like wind and solar, with load. It does this by storing surplus energy when wind and solar generation exceed load and by discharging storage when wind and solar output drop below load. Similarly, from a customer's perspective, distributed storage paired with distributed solar generation helps the customer make use of more of their on-site generation to serve their own load. This reduces the energy they would otherwise export to the grid and later repurchase from the grid when solar production does not align with their use.

#### 5.3.6.1 Distributed generation solar and distributed storage forecast study results

The DER Study evaluated the adoption of distributed generation solar and distributed storage. The solar adoption forecast model considered historical rates of adoption and evaluated future adoption based on several parameters that varied across four scenarios. Some solar was assumed to be adopted alone, some was assumed to be adopted with distributed storage and some distributed storage was assumed to be adopted alone. Table 5 summarizes the driving factors for each scenario considered in the study.

| Parameter | Low scenario | Medium scenario | Medium export-rate scenario | High scenario |
|---|---|---|---|---|
| **Policy/program interventions** | | | | |
| Solar and storage incentives | Federal ITC (solar tax credit) benefits phased out early (2028).<br><br>No owner community incentives. | Federal ITC, phased out on schedule (2035)<br><br>Current Fort Collins incentives, phased out 2028 | | Federal ITC extended to 2040.<br><br>Fort Collins incentives adopted by all owner communities. |
| Codes and standards | No mandates | All new buildings must have solar beginning 2030. A gradual increase is assumed 2024 – 2030. | | All newly constructed buildings must have solar beginning in 2024 (commercial) and 2027 (residential) |
| Retail net energy metering (NEM) and export compensation | Current NEM and export compensation (Fort Collins time of use and other owner communities' flat rates) | New NEM:<br><br>All communities adopt time of use (TOU) rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail | New NEM with exports valued at forecasted wholesale energy market rates | New NEM:<br><br>All communities adopt TOU rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail |
| Incentive for storage participation in VPP | None | $150/kW-yr. | | $216/kW-yr. |
| Storage adoption relative to solar | 10% of solar includes storage | 30% of solar includes storage | 50% of solar includes storage | 30% of solar includes storage |
| **Technology factors** | | | | |
| Distributed solar cost | Limited cost decline (historical regional cost + future NREL solar cost decline) | Moderate cost decline (historical regional cost + future NREL solar cost decline) | | Aggressive cost declines (historical regional cost + future NREL solar cost decline) |
| Distributed storage cost | Limited NREL storage cost decline | Moderate NREL storage cost decline | | Aggressive NREL storage cost decline |

**Table 5.** *Adoption of distributed generation – solar and storage*

The DER Study considered a range of assumptions. First, the DER Study assessed the impact of federal investment tax credits, with the assumption ranging from early phaseout, in 2028, compared to scheduled phaseout, in 2035, and extended phaseout in 2040. Owner community incentives were also considered, ranging from none to Fort Collins's current incentives, to adoption of Fort Collins' incentives by the other three owner communities. In all cases, the incentives were assumed to phase out in 2028, coinciding with the significant increase in Platte River's noncarbon portfolio. The study evaluated new building standards ranging from no solar requirement to increasingly stringent requirements for new construction to include solar.

The study also considered the effect of retail rates, and specifically net energy metering (NEM), on distributed generation solar and distributed storage adoption. NEM refers to the financial compensation customers with solar (and increasingly customers with solar and distributed storage) can receive due to both reduced purchases of electricity from their retail electricity provider and due to exporting excess solar and distributed storage output to the grid whenever solar and storage produce more energy than the customer consumes.

The study evaluated a range of possible NEM rates. The **low scenario** assumed existing NEM rates apply. This includes Fort Collins's existing time-of-use rate, which charges higher rates during on-peak periods (weekdays, 2 to 7 p.m. during summer months and 5 to 9 p.m. in other months) and lower rates all other hours. Exported energy is credited on the same schedule, but at rates that are 10 to 20% lower. The other owner communities largely have time-invariant rates and compensate exports at or close to the retail rate.

The **medium and high scenarios** assumed all owner communities adopt a rate structure like Fort Collins and that the summer on-peak period shifts later in the day, to 5 to 9 p.m., for all communities. This is due to anticipated high adoption of solar by customers and by Platte River. This results in reduced demand for energy and ample supply when solar energy is available, followed by higher demand and reduced supply as the sun sets and solar output diminishes and then stops. This will lead to higher energy costs as the sun sets and after the sun is down.

The **medium export-rate scenario** assumed the financial value of solar will erode due to higher solar adoption by customers, Platte River and other utilities in the region; low energy prices when solar is plentiful, followed by high prices when solar is absent. Achieving greater value from the solar energy will require that it be shifted in time, from peak solar hours to hours just after the sun sets, which can be achieved through increased deployment and use of energy storage (whether distributed or utility-scale). Modifying the retail rate to compensate exported solar at the wholesale rate will better reflect the value solar alone brings to the system, and at the same time provide value to customers who adopt and use distributed storage to reduce exports and use more solar energy at the home or business.

The study also assessed the adoption of distributed storage. This is projected to be driven by rates and the rate structure as well as on incentives that could be paid to customers to adopt distributed storage and to enroll distributed storage in a VPP for Platte River to dispatch. The combined impact of changes to net energy metering, export compensation and

VPP incentives, coupled with declines in storage costs, are projected to drive higher adoption of storage with solar – increasing from the low scenario (in which 10% of solar was assumed to include storage) to 50% for the medium-export scenario.

Platte River also constructed a fifth scenario, which starts with the medium scenario and then shifts over a period of about 10 years to the medium export-rate scenario.

Figures 23 and 24 illustrate the forecasted adoption of distributed solar and storage, respectively.

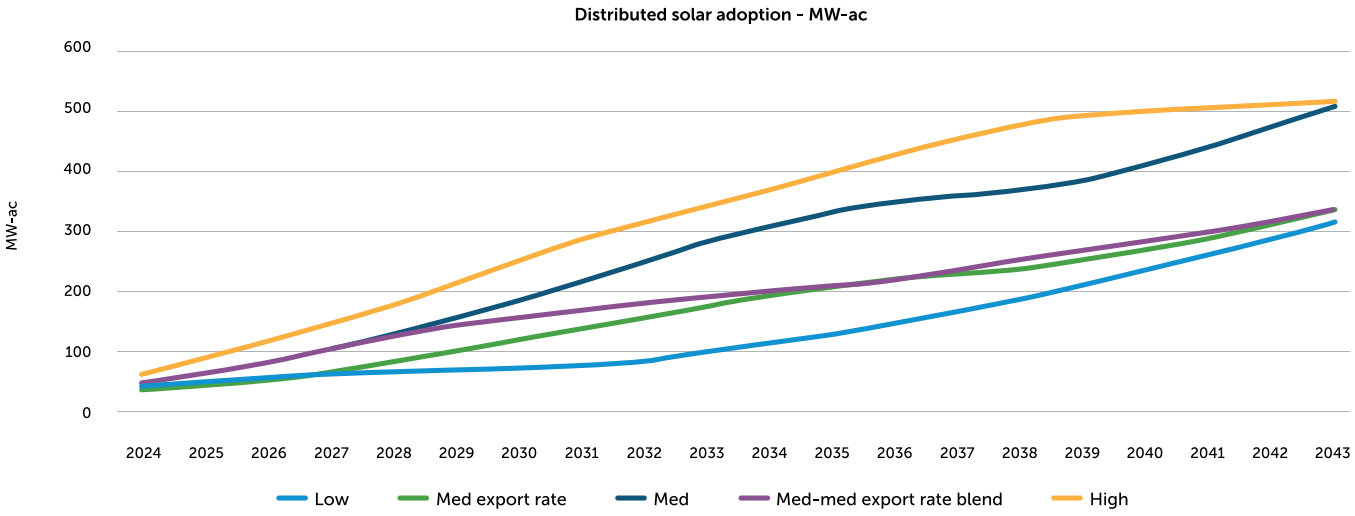



**Figure 23.** *Distributed solar adoption - MW-ac*

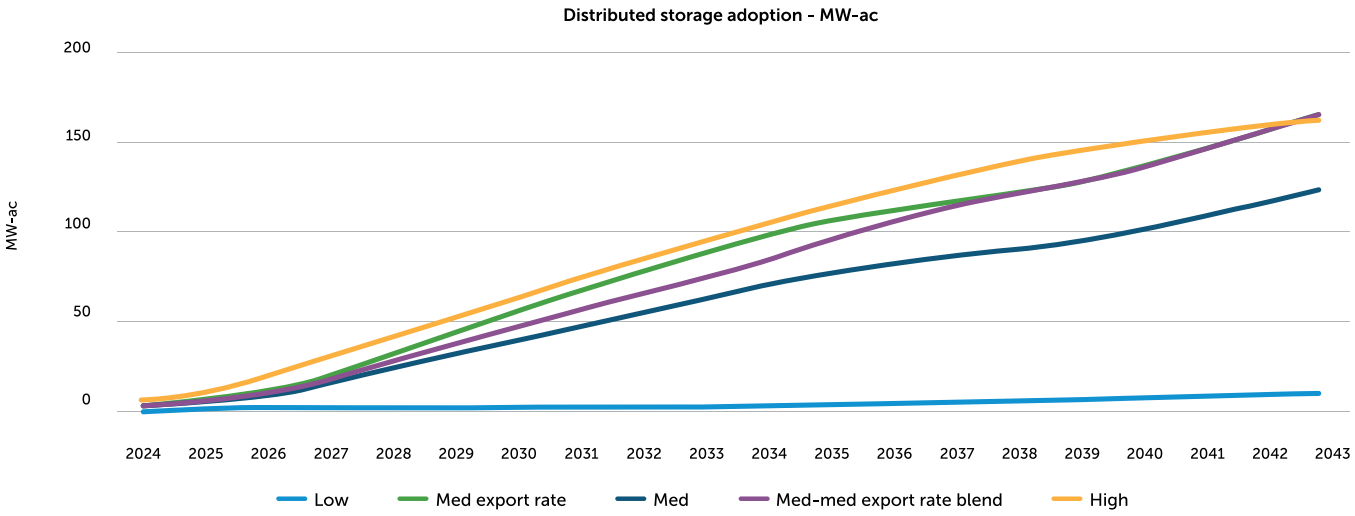



**Figure 24.** *Distributed storage adoption - MW-ac*

**Monitoring and forecasting distributed generation solar and distributed storage adoption.** The rise of distributed generation within the owner communities has primarily been driven by individual customers adopting rooftop solar power. Solar energy constitutes around 94% of the existing distributed generation capacity. The remaining capacity is divided among wind (0.02%), cogeneration (4.1%) and hydropower (1%).

Figure 25 illustrates the growth of distributed solar capacity within Platte River's network, fueled by available federal and local incentives, coupled with customers' economics and drive to reduce carbon emissions from electricity generation. As of the end of 2022, estimated distributed solar within Platte River's owner communities totaled 36.3 MW (AC), with 63% from residential solar, 17% from commercial solar, and 20% owned or procured by Platte River or the owner communities.

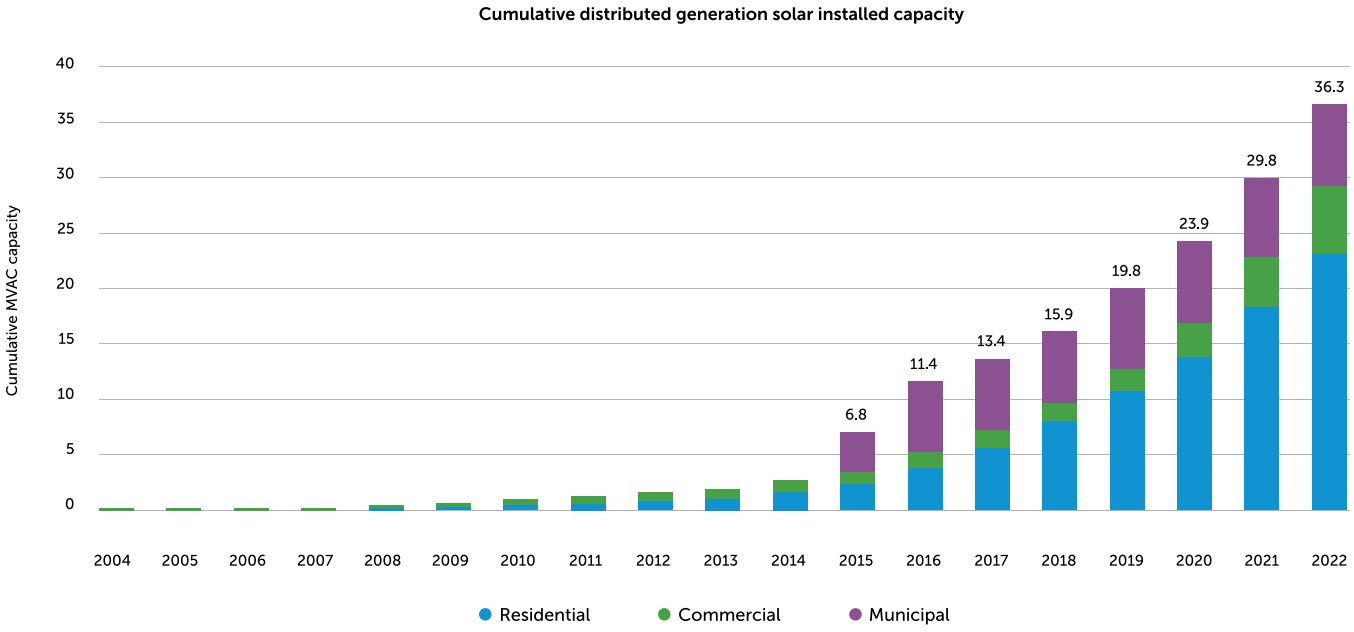



**Figure 25.** *Cumulative distributed generation solar installed capacity*

Between 2017 and 2022, there has been a notable increase in distributed storage deployment, raising the total capacity to about 1.2 MW in the owner communities. This comprises about 175 systems, averaging a discharge rate of about 7 kW per system. Each year since 2017, there has been an increase in distributed storage system interconnections, with the highest number of installations in 2022. This significant rise highlights the widespread adoption of storage solutions, particularly battery storage, as a versatile tool for providing backup energy and enhancing the operational efficiency of distributed solar systems.

The DER Study evaluated a range of distributed generation solar and distributed storage adoption scenarios to inform the load forecast used for resource planning and to inform DER planning.

Platte River has chosen the blend of the medium and medium-export-rate forecasts. This combination of scenarios represents a gradual change in NEM rates that improves the financial benefit of adopting distributed storage with distributed generation solar. This forecast indicates approximately 155 MW distributed generation solar and 47 MW distributed storage by the end of 2030. This represents 20% annual growth in installed solar capacity and 48% annual growth in storage capacity from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

### 5.3.7 Flexible DERs and the virtual power plant

As described in previous sections, a VPP is an aggregation of flexible DERs that can be dispatched to support electric system reliability, financial benefits and individual customer benefits. As the name suggests, the VPP can act like a power plant, but it is different in that it is created by thousands of DER devices operating across the electric system. They act in concert, enabled by communication, data collection and management, control and optimization technology.

#### 5.3.7.1 Flexible DER and VPP forecast study results

The DER Study included an assessment of flexible DER that could provide VPP capacity. VPP capacity was evaluated using a multi-step approach that considered the technical, economic and achievable potential of flexible DER technology combined with utility program approaches:

- Technical potential assesses the quantity of flexible DER capacity that theoretically exists in the owner community service territory and how it is expected to grow over time.
- Economic potential considers how much of the technical potential is economic compared to other utility resource options. The study relied on the total resource cost test framework, which compares the marginal costs of a VPP resource for Platte River, the owner communities and their customers to the marginal cost of utility resources.
    - The cost of utility resources included hourly energy costs based on forecasted market energy prices, carbon tax, capacity costs based on four-hour storage and distribution capacity costs based on owner community estimates.
    - The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
    - The cost of achieving VPP potential did not include the cost to the utility of VPP-enabling technology and systems. The need for enabling technology and systems is unaffected by which flexible DER programs Platte River and the owner communities offer.
- Achievable potential considers how much of the economic potential can be realized as a dispatchable VPP capacity at the time of system need and considering customer enrollment rates in VPP program.

The potential study assessed achievable capacity at times of high "net load." This was defined as the load that remains after deducting wind, solar and hydropower. Figure 26 illustrates what this might look like in 2030. Note that while only one day is shown, there are multiple days each summer that would have a similar, though slightly smaller, peak net load. As a result, flexible DER capacity is required many hours throughout the summer. As electrification increases winter loads at a more rapid rate than summer loads, the need for winter dispatchable capacity will grow as well.

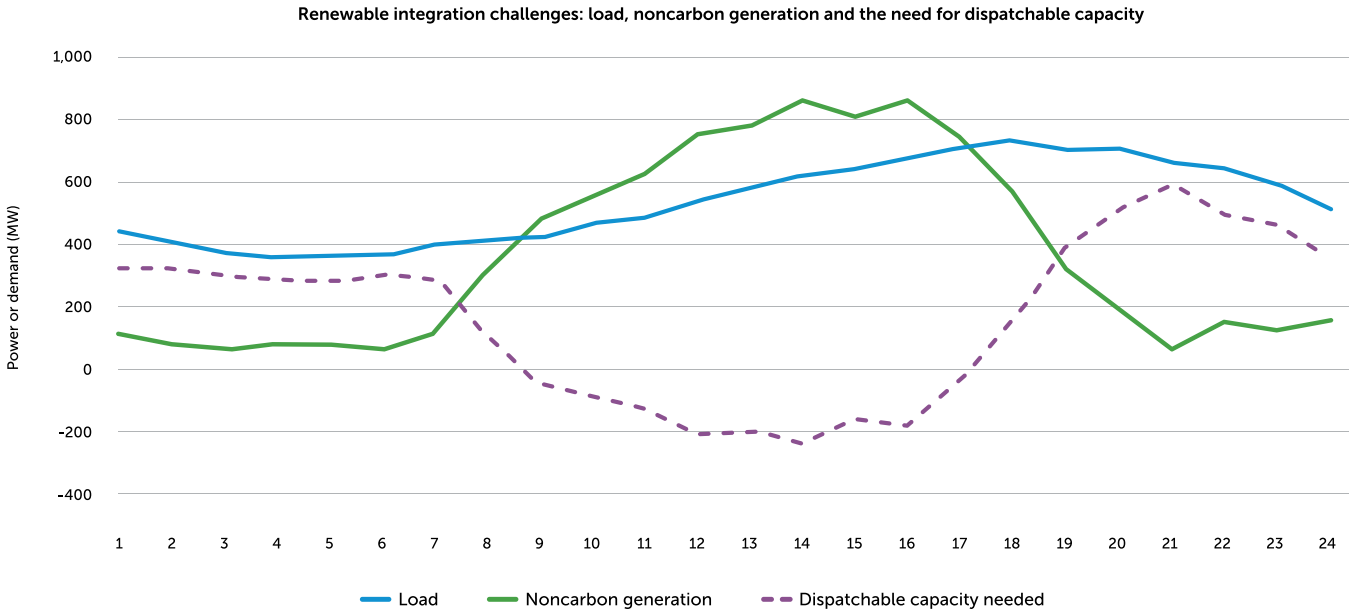



**Figure 26.** *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

The DER Study assessed a variety of factors that could drive varying levels of achievable VPP capacity. These were combined in four scenarios as shown in Table 6.



| Parameter | Low scenario | Medium scenario | Medium export-rate scenario | High scenario |
|---|---|---|---|---|
| Time-varying rates | Existing residential TOU rates in Fort Collins only (summer on-peak 2 – 7 p.m.) | New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak) | New residential TOU with solar exports valued at forecasted wholesale energy market rates | New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak) |
| Program marketing and incentives | Industry-standard marketing and incentives | Industry-standard marketing and incentives | Industry-standard marketing and incentives | Maximum cost-effective marketing and incentives |
| Efficiency scenario | Low | Low | Low | High |
| Electric vehicle scenario | Low | Medium | Medium | High |
| DS solar and storage scenario | Low | Medium | Medium export-rate | High |

**Table 6.** *Primary drivers of achievable VPP capacity*

Within each scenario, various flexible DER approaches were evaluated in an interactive model to determine how they could be combined to provide a sustained reduction in the system net peak, considering the impact of time-varying rates, direct-control programs and each DER's operating characteristics, as summarized in Table 7.



| Measure group | Measure sub-group | Characteristics | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Curtail-ment potential | Event duration (hours) | Pre-charge time | Pre-charge sizing | Rebound time | Rebound sizing (per hour) | Event frequency (per year) |
| **HVAC controls** | Smart thermostats | [75%, 33%] | Up to 2 h | 1 h | 40% | 2 h | 30% | 20 |
| **EV charging** | EV smart chargers | 100% | 4 h + | N/A | N/A | 6 h | 17% | 300+ |
| | Vehicle-to-grid | 100% | 4 h + | N/A | N/A | 6 h | 17% | 300+ |
| **Water heating** | Electric water heaters | 100% | Up to 4 h | 2 h | 17% | 4 h | 17% | 15 |
| **Other loading flexibility** | Large C&I curtailment | 25% | Up to 4 h | N/A | N/A | N/A | N/A | 15 |

**Table 7.** *Flexible DER operating characteristics – load*

| Measure group | Measure sub-group | Characteristics | | | | | |
|---|---|---|---|---|---|---|---|
| | | Size (kW) | Curtail-ment potential | Round trip efficiency | Typical event duration (hours) | Typical rebound / pre-charge time | Typical event frequency (per year) |
| **Storage** | Battery storage - residential | 3.3 | 33% | 85% | 4 h | 4 h | 300+ |
| | Battery storage – small commercial | 5 | 100% | 85% | 4 h | 4 h | 300+ |
| | Battery storage – large commercial | 50 | 100% | 85% | 4 h | 4 h | 300+ |

**Table 8.** *Flexible DER operating characteristics – storage*

- For residential, it is assumed 33% of the battery is available for flexible DER program, with the remainder used for customer resiliency.
- For commercial batteries, 100% is assumed available for flexible DER, as batteries are typically used for peak load management, and backup generators are used for resiliency.



As illustrated in tables 7 and 8, the flexibility of EVs and battery storage is apparent, with both having the ability to be dispatched on a near-daily basis, 300 times annually. This provides potential for a highly flexible, available resource that can be used to balance variable noncarbon generation. Flexibility of other DERs, such as HVAC control, large commercial and industrial curtailment and water heater control will be limited due to impacts on comfort and productivity.

Figures 27 and 28 summarize the resulting achievable capacity for each of the cases, as well as the annual costs in 2030 and 2040. Program costs are strictly incentives and program administration. They do not include VPP system costs. Growth from 2030 to 2040 was driven largely by increasing adoption of battery storage and EVs.

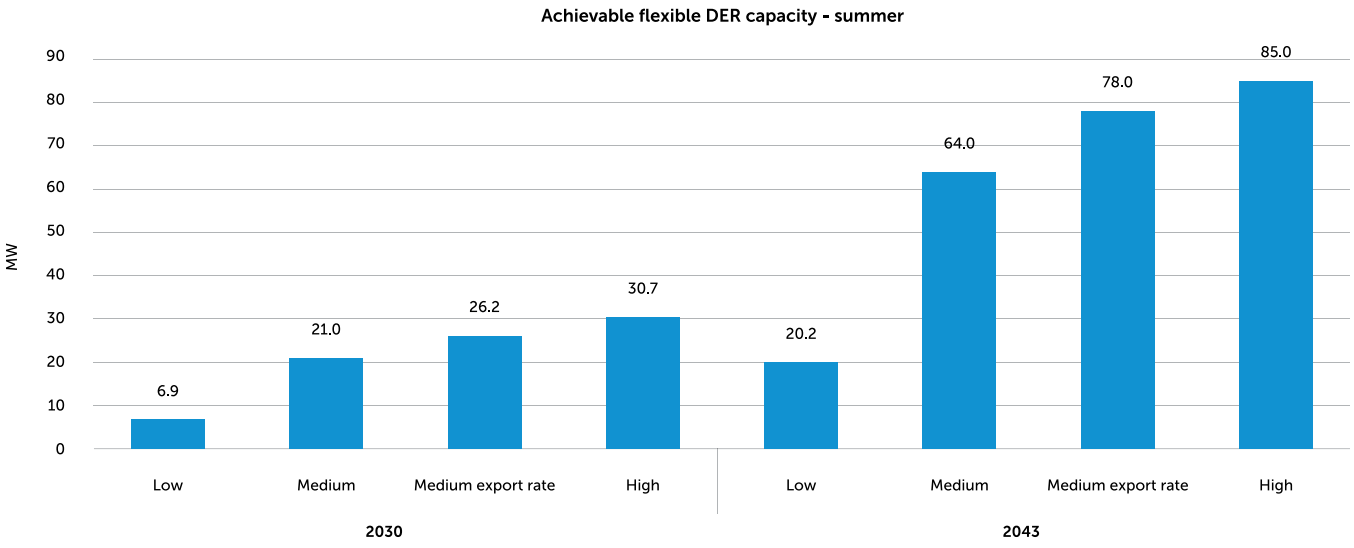



**Figure 27.** *Achievable flexible DER capacity - summer*

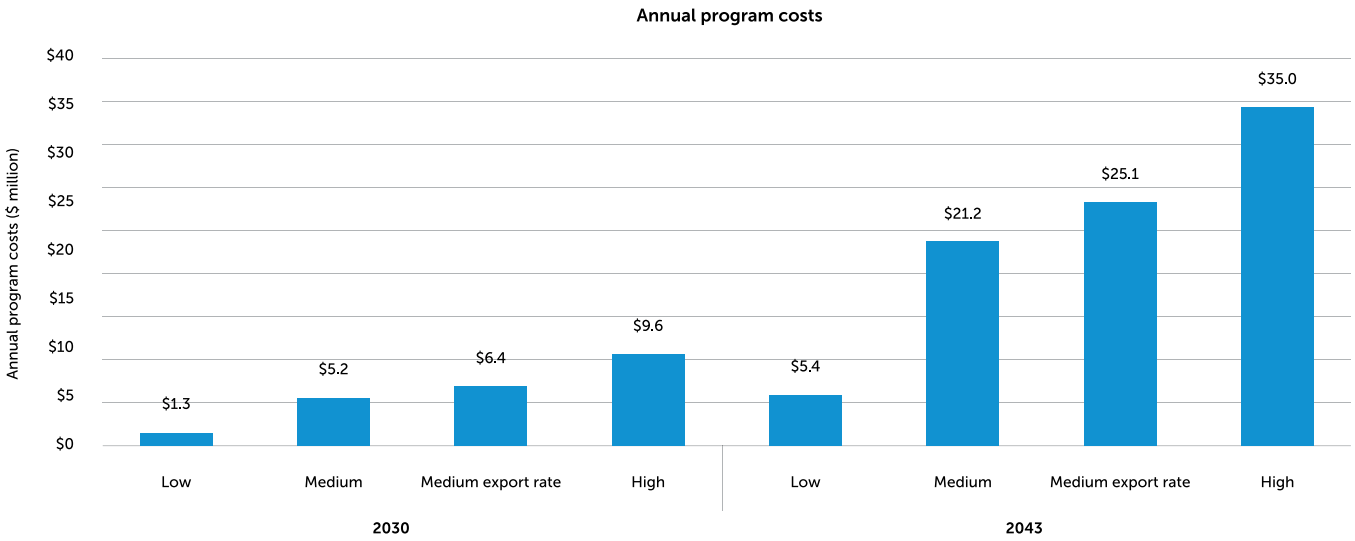



**Figure 28.** *Annual program costs*

Key takeaways from the DER Study include:

- Summer peak load reductions range from 6.9 MW to 30.7 MW across the different scenarios in 2030.
- The commercial sector is forecasted to have the greatest potential for the low scenario while the residential sector overtakes commercial in the medium and high cases, due to increasing adoption of EVs and distributed storage.
- For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the summer and electric resistance smart thermostats in the winter.
- The commercial demand response potential is primarily driven by large commercial and industrial opportunities, followed by battery storage and water heating.

**Develop and implement VPP customer programs.** Customers who have flexible DERs and are willing to enroll them in the VPP provide the engine for the VPP's operation. Therefore, a major focus of Platte River and the owner communities is to develop customer programs that support customer enrollment and ongoing participation.

Customer programs must support Platte River's pillars of providing reliable, environmentally responsible and financially sustainable energy, while also providing benefits to participating customers. The DER Study has identified the following opportunities for flexible DERs that can participate in the VPP:

- **Distributed storage management.** Distributed storage is expected to grow significantly, often paired with distributed generation solar.
- **EV charge management (including vehicle-to-grid when available)**. EV

adoption is expected to grow significantly, providing a large and highly flexible load for the VPP. Vehicle-to-grid is also anticipated to grow, with the potential of providing additional storage to the grid.

- **Large commercial and industrial customer custom demand response.** These customers are likely to have large and sometimes unique DER opportunities. Platte River anticipates developing custom approaches to support these projects similar to the custom, pay-for-performance incentives currently offered for efficiency improvements.

- **HVAC demand response.** HVAC demand response programs manipulate electric load for heating and cooling buildings for short periods of time, either through direct control of the heating or cooling system components (for example, compressor load-control switches) or increasingly, through wi-fi enabled thermostats ("smart thermostats").

- **Electric water heater demand response and storage.** Electric water heater demand response takes advantage of the storage that is typically integral to the water heat to allow active heating to be curtailed for brief periods.

Taken together, these customer resources are anticipated to provide a VPP capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040. To improve the availability of this capacity, Platte River anticipates enrolling more DER capacity than these values indicate. This is to account for limitations on the flexibility of DERs to consistently provide capacity during the evening peak while respecting customer restrictions on Platte River's and the owner communities' use of their flexible DERs. As a result, the enrolled capacity of customer resources may reach an estimated 71 MW by 2030 and 204 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

In addition to the customer resources, the VPP is anticipated to include other flexible DERs developed by Platte River and the owner communities. Platte River is in developing plans for 20 MW of distribution-scale storage to be located within the owner communities. This is expected to bring the total achievable VPP capacity to about 52 MW by 2030 and 113 MW by 2040.

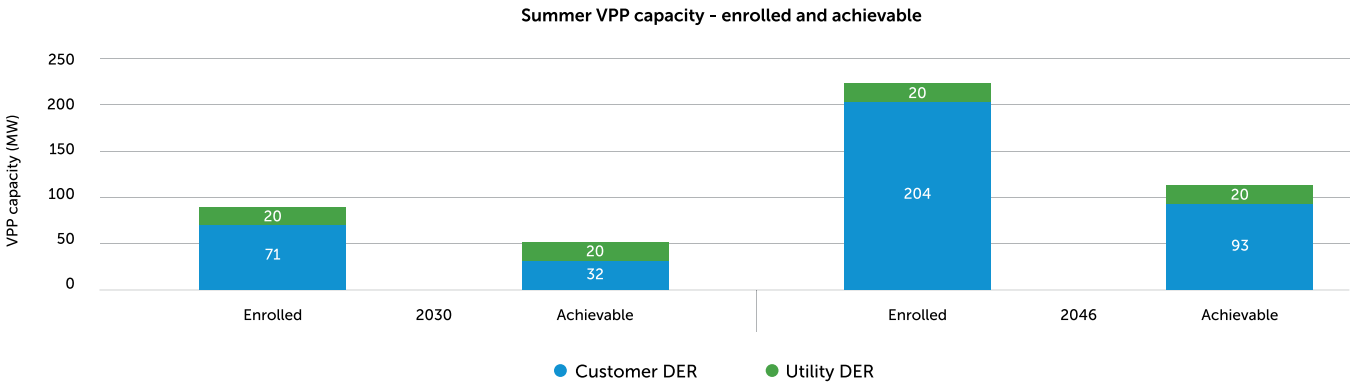



**Figure 29.** *Summer VPP capacity - enrolled and achievable*



Achieving a VPP of this magnitude requires a high level of customer participation. The enrolled capacity is projected to include 50,000 DER devices by 2030 and close to 100,000 devices by 2040, drawn from the owner communities' customer base of about 172,000 customers. To achieve this high level of participation, Platte River will collaborate with the owner communities to support customers on their DER journeys. This includes engaging customers as they evaluate their DER options and consider enrollment in the VPP. It is also expected to include providing incentives for enrollment and ongoing participation based on the system benefits their DERs can provide. In addition, Platte River and the owner communities will need to engage with the local, regional and some national market actors in the manufacturing, distribution, sales, installation, and operation of DERs.

Platte River issued an RFP in May 2024 to identify firms experienced in providing VPP customer program deployment to provide a rapid, cost-effective, and customer-focused portfolio of VPP programs.

### 5.3.8 Summary of selected scenarios for DER and VPP potential

Platte River evaluated a range of DER potential scenarios, ranging from low to high. Table 9 summarizes the scenarios selected for each type of DER and describes the reason the scenario was selected.

| DER type | Selected scenario | Description |
|---|---|---|
| Energy efficiency | Low | Low scenario is most consistent with current participation levels, even as Efficiency Works offers some of the highest efficiency incentives in the state. |
| Building electrification | Medium | Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification. |
| Transportation electrification | Medium | Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification. |
| Distributed generation and storage | Medium-medium export rate | A hybrid scenario starting with medium and shifting to medium export rate was used to reflect current adoption trends and anticipated shifts in net metering policy to favor storing excess solar rather than exporting it. |
| Virtual power plant / flexible DERs | Hybrid – see description | A hybrid scenario was defined in part by the DER adoption scenarios described above. In addition, EVs that the study assumed would respond to time-varying rates were instead reclassified as being under direct load management to provide greater responsiveness to varying system conditions. The result is that the selected VPP potential is close in magnitude to the high scenario. |

**Table 9.** *Summary and logic for selected scenarios*

## 5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast before considering the impact of DERs. In section 5.3, we covered different DERs and saw how much energy and peak demand they contribute (like distributed solar or demand response) and require from the system (like EVs and building electrification). This section discusses the energy and peak demand contribution of each DER and the composite load forecast including the contributions from all the DERs. The composite load forecast, including energy and peak demand, was used in the Plexos model to develop a supply-side portfolio.

## 5.4.1 Energy contributions of DER

### 5.4.1.1 Distributed generation

Figure 30 shows the energy contribution from distributed generation, primarily distributed solar. This is shown as negative because it represents the reduction in customer energy needs from Platte River's supply. The bars show energy in gigawatt-hours (GWh) and the solid line shows percent reduction in total Platte River energy. By 2030, distributed generation energy is expected to reduce base energy by 6% and by the end of planning horizon in 2043, it is expected to reduce the predicted base energy by about 13%. Distributed solar produces more energy in summer and less energy in winter but these are annualized values.

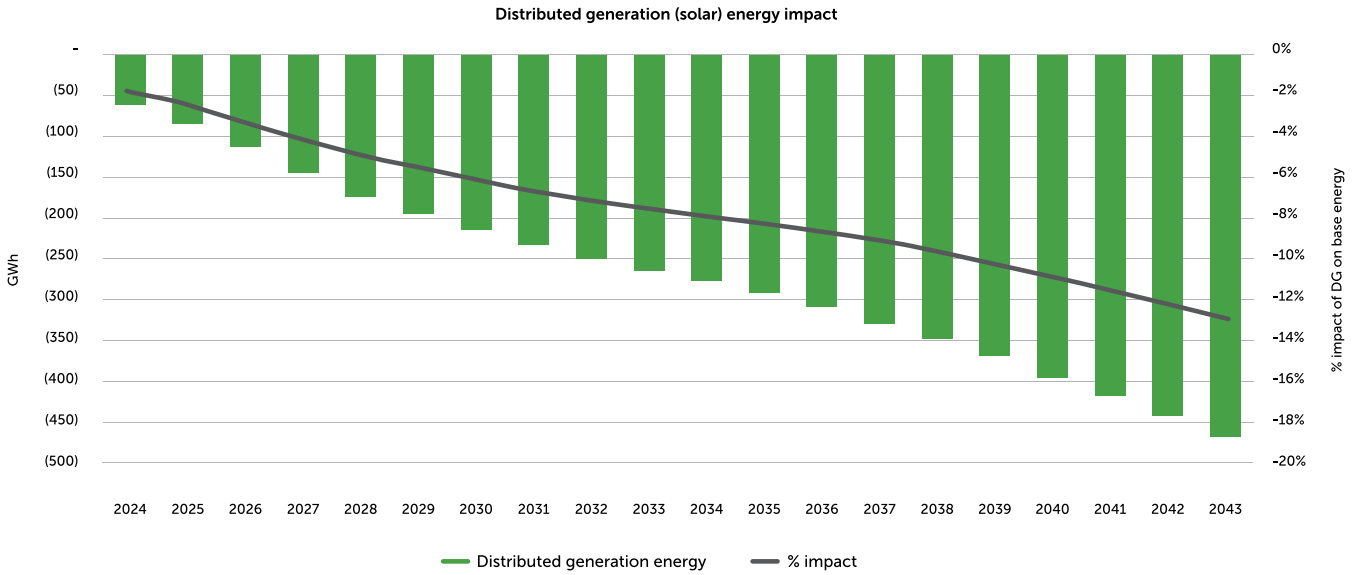



**Figure 30.** *Distributed generation (solar) energy impact*

### 5.4.1.2 Building electrification

As illustrated in Figure 31, building electrification (mostly consisting of heating load) starts from a very small level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows the percent increase in the base energy forecast. By 2030, building electrification is expected to increase base energy by 3% and by the end of the planning horizon in 2043, it is expected to add about 19% to the predicted base energy. Because it is heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

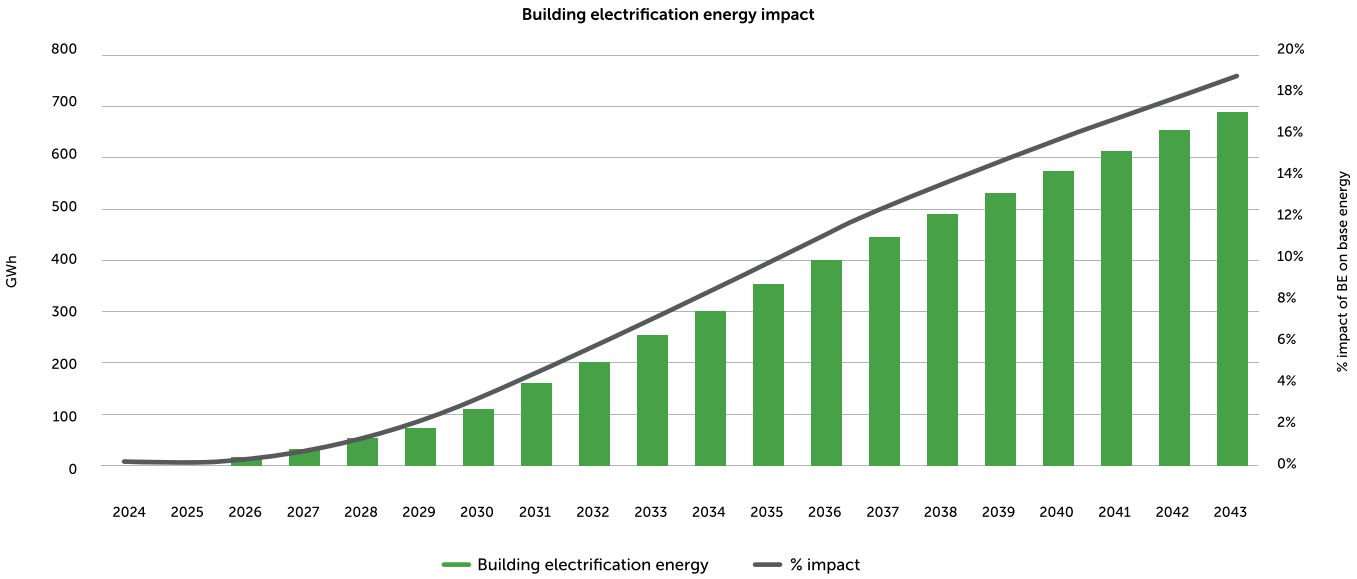



**Figure 31.** *Building electrification energy impact*

## 5.4.1.3 Electric vehicles

As illustrated in Figure 32, EV load starts from a very low level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows percent increase in the base energy forecast. By 2030, EV is expected to increase base energy by 5% and by the end of the planning horizon in 2043, it is expected to add about 23% to the predicted base energy. These are annual values. EV load is evenly distributed across the year. A portion of the EV load is flexible and exact charging time can be managed by the utility to more opportune times.

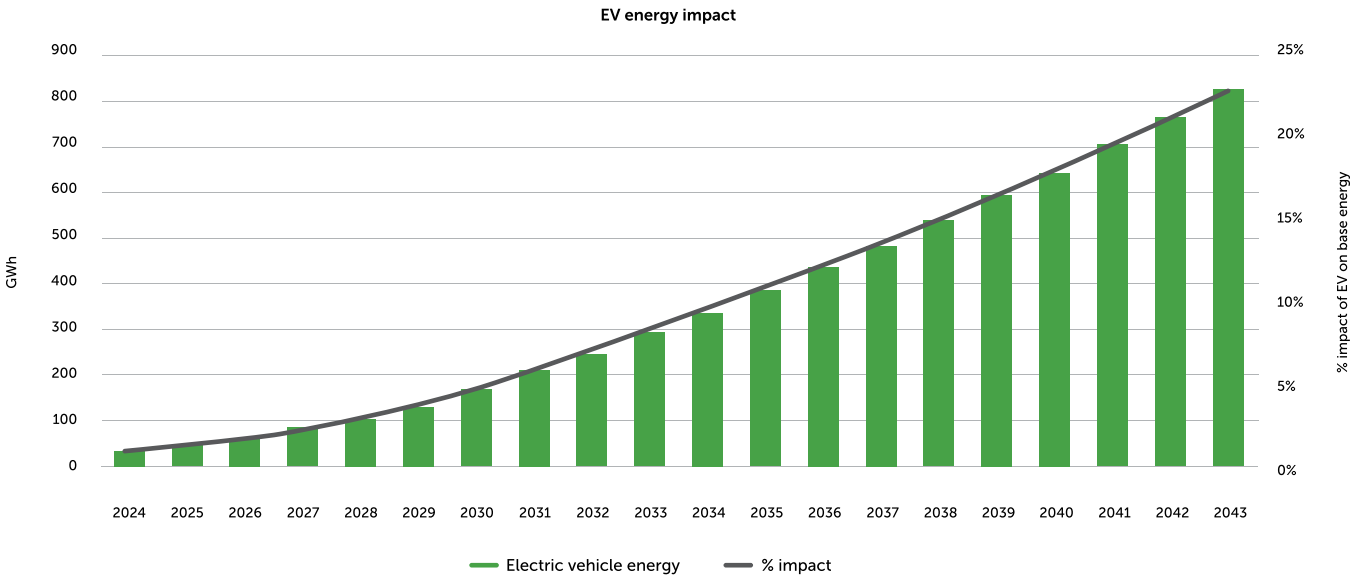



**Figure 32.** *EV energy impact*

## 5.4.2 Capacity contribution of DER

### 5.4.2.1 Distributed generation

Figure 33 shows the summer peak capacity contribution from distributed generation. This is shown as negative because this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, distributed generation is expected to reduce summer peak by 2% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 3.4%. Although the absolute megawatt addition of rooftop solar is large, its impact on the summer peak is small due to low Effective Load Carrying Capability (ELCC) value of distributed solar (like utility scale solar). Basically, the incremental contribution of solar to reduce summer peak becomes negligible to zero as more solar is added and the peak hour moves closer to the sunset.

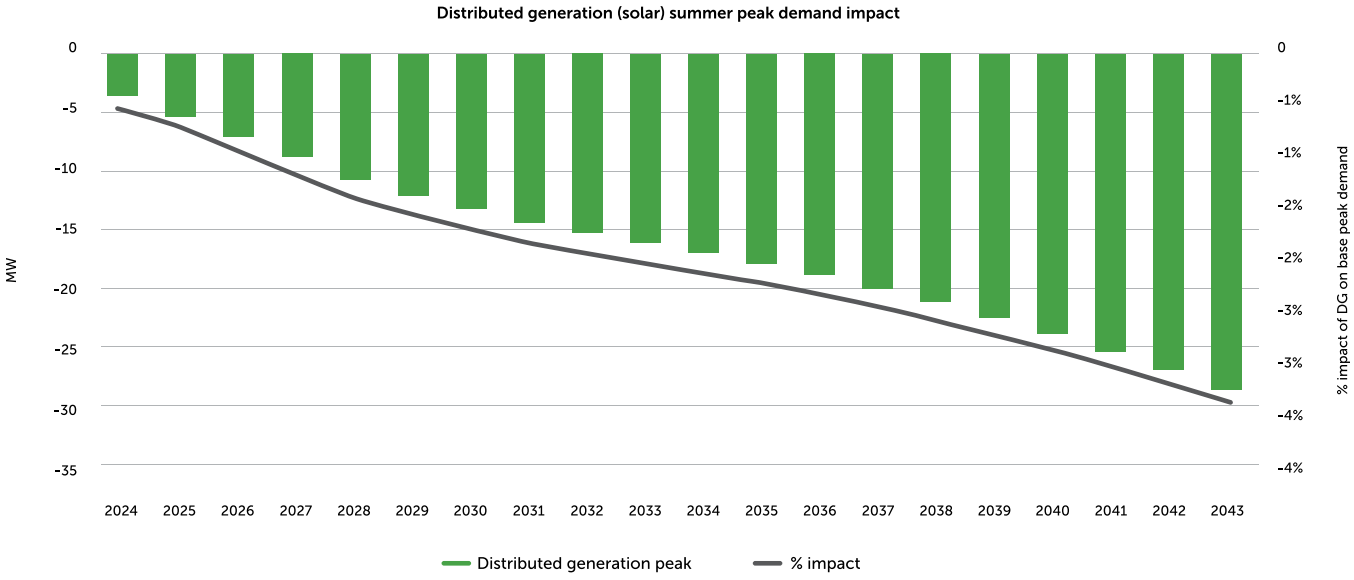



**Figure 33.** *Distributed generation (solar) summer peak demand impact*

### 5.4.2.2 Demand response

Figure 34 shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown as negative because it represents the reduction in overall customer peak demand. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, demand response is expected to reduce summer peak by 5% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 9%.

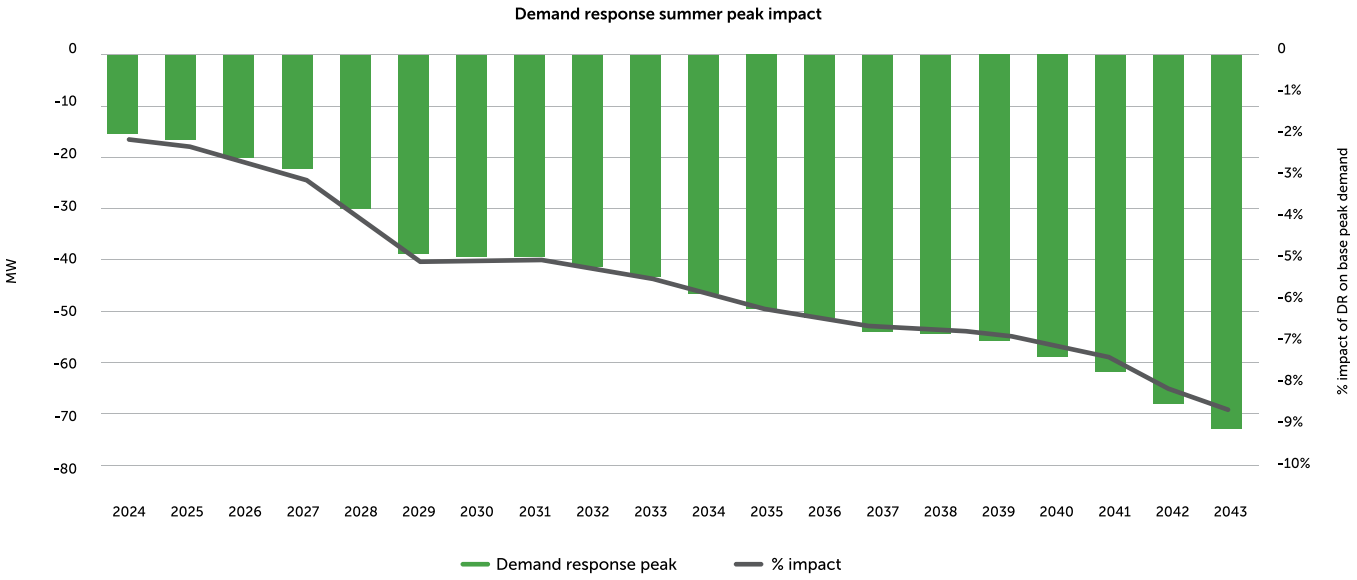



**Figure 34.** *Demand response summer peak impact*

## 5.4.2.3 Building electrification

As illustrated in Figure 35, building electrification starts from a very low level but is expected to grow rapidly in the next decade. Most building electrification contribution is from heating systems in colder months, so the impact on summer peak demand is fairly small, mainly coming from electric cooking and water heating. The bars show summer peak hour building electrification load in megawatts and the solid line shows percent increase in the base peak demand. By 2030, building electrification is expected to increase summer base peak by about 1% and by the end of the planning horizon in 2043, it adds about 3% to the predicted base summer peak demand.

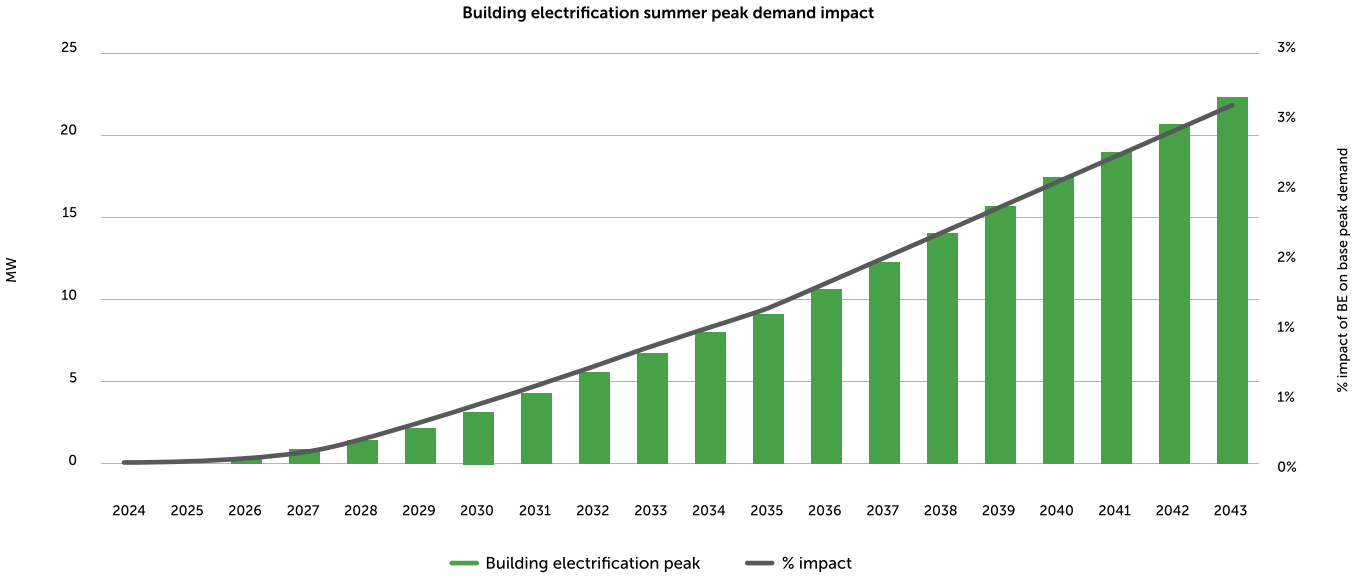



**Figure 35.** *Building electrification summer peak demand impact*

### 5.4.2.4 Electric vehicles

As illustrated in Figure 36, electric vehicle load starts from a very low level but is expected to grow rapidly in the next decade. This figure shows the portion of the EV load that is inflexible and cannot be managed or moved away from the summer peak hour. The bars show summer peak capacity in megawatts and the solid line shows percent increase in the summer base peak demand forecast. By 2030, EV is expected to increase summer base peak demand by 3% and by the end of the planning horizon in 2043, it adds about 15% to the predicted base summer peak demand. It is important to note that most EV load is flexible, and its exact charging time can be managed by the utility to lower summer peak demand. Contribution from the flexible EV charging load is not included in the chart below because we assume it will be controlled at the time of summer peak hour and moved to a later, lower-demand hour.

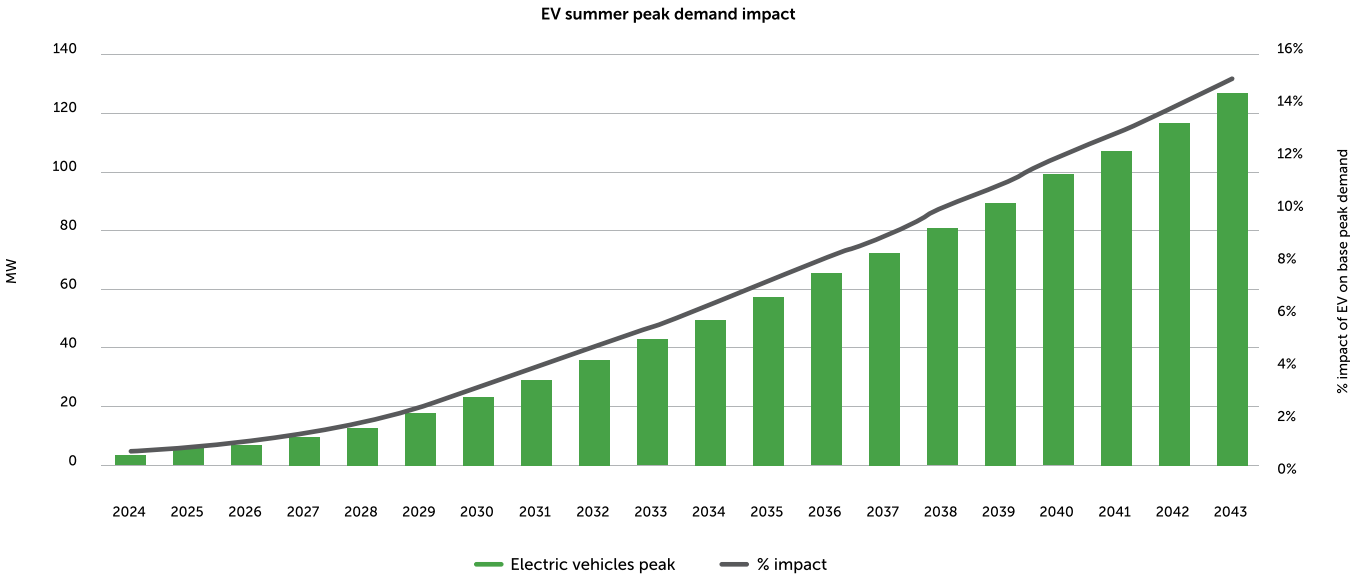



**Figure 36.** *EV summer peak demand impact*

## 5.4.3 Composite load with all DER contributions

Collectively, DERs decrease electric consumption and load growth in early years, due to the presence of distributed generation resources like rooftop solar and demand response programs, offsetting additional load created by electric vehicles and building electrification. However, as adoption of electric vehicles and building electrification increase, the additional load outpaces growth in distributed generation, resulting in higher load growth. The combined DER impact trend is similar for annual energy and summer peak demand but the percent impact varies. Figure 37 shows composite annual energy requirements and the combined percent impact of DERs.

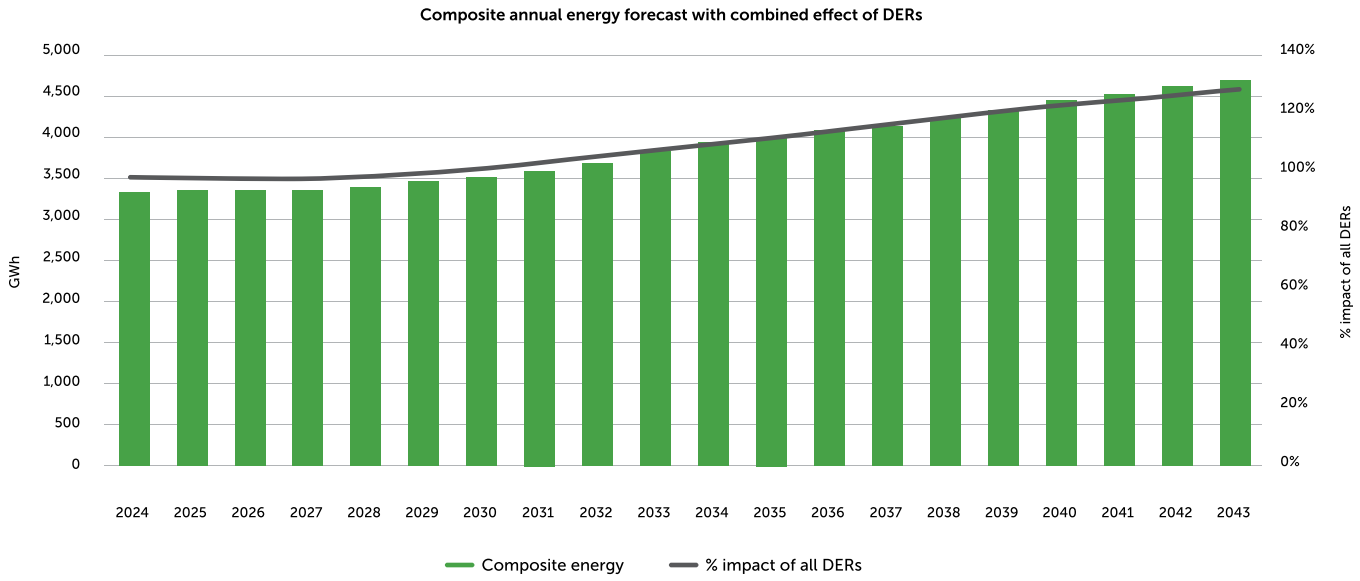



**Figure 37.** *Composite annual energy forecast with combined effect of DERs*

The green bars in Figure 37 show composite annual energy in gigawatt hours that Platte River's supply system must produce, and the solid black line shows the combined impact of all DERs as a percent. The combined effect of DERs reduces the annual energy need through 2029 and increases it afterwards, due to rapid increase in building electrification and EV load, reaching an almost 29% increase by 2043.

Figure 38 shows composite summer peak requirement and the combined percent impact of DERs. The green bars show composite summer peak demand in megawatts that Platte River's supply system must provide, and the solid black line shows the combined impact of all DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increases it after, due to rapid increase in building electrification and EV load, reaching an almost 6% increase by 2043. The combined percent impact of DERs on summer peak demand is much lower than the percent impact on annual energy consumption because the two major DERs, EV and building electrification, do not increase the summer peak load as much as they increase annual energy consumption.

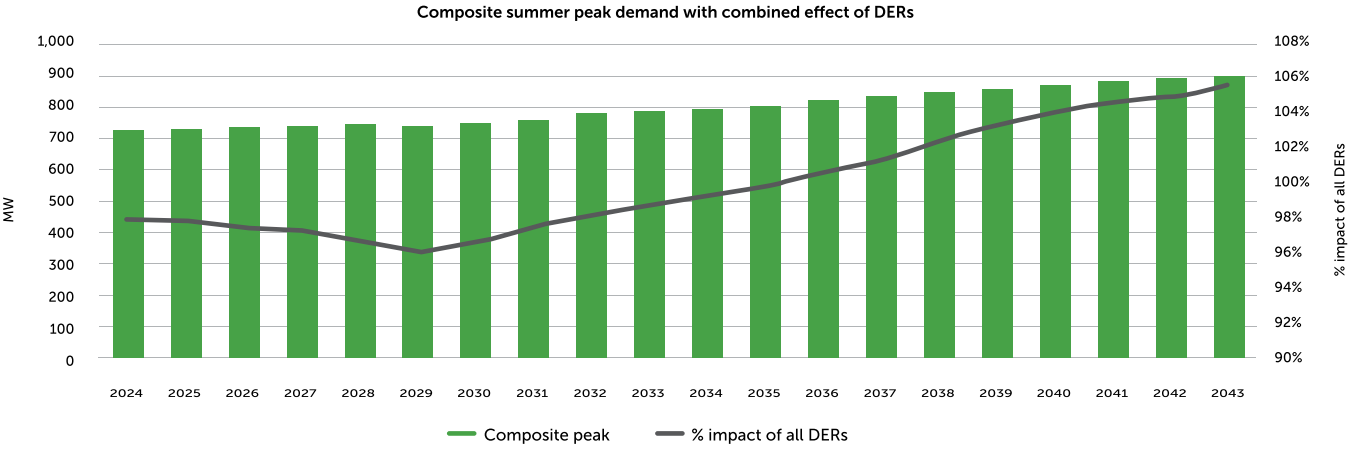



**Figure 38.** *Composite summer peak demand with combined effect of DERs*



# 06 Supply-side assumptions

This section reviews assumed supply-side resources available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well as assumptions about how Platte River interacts with other power suppliers in our region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

## **6.1** Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power, carbon dioxide (CO2), nitrogen oxides, sulfur dioxide (SO2), and mercury cost projections. Platte River projected coal prices based on unique coal supply plans for its coal-fired generation fleet. The following subsections discuss these commodity price projections in more detail.





## 6.1.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition to the base case pricing, Siemens also provided high and low gas price projections the planning team used to develop sensitivity cases. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market, such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 39.

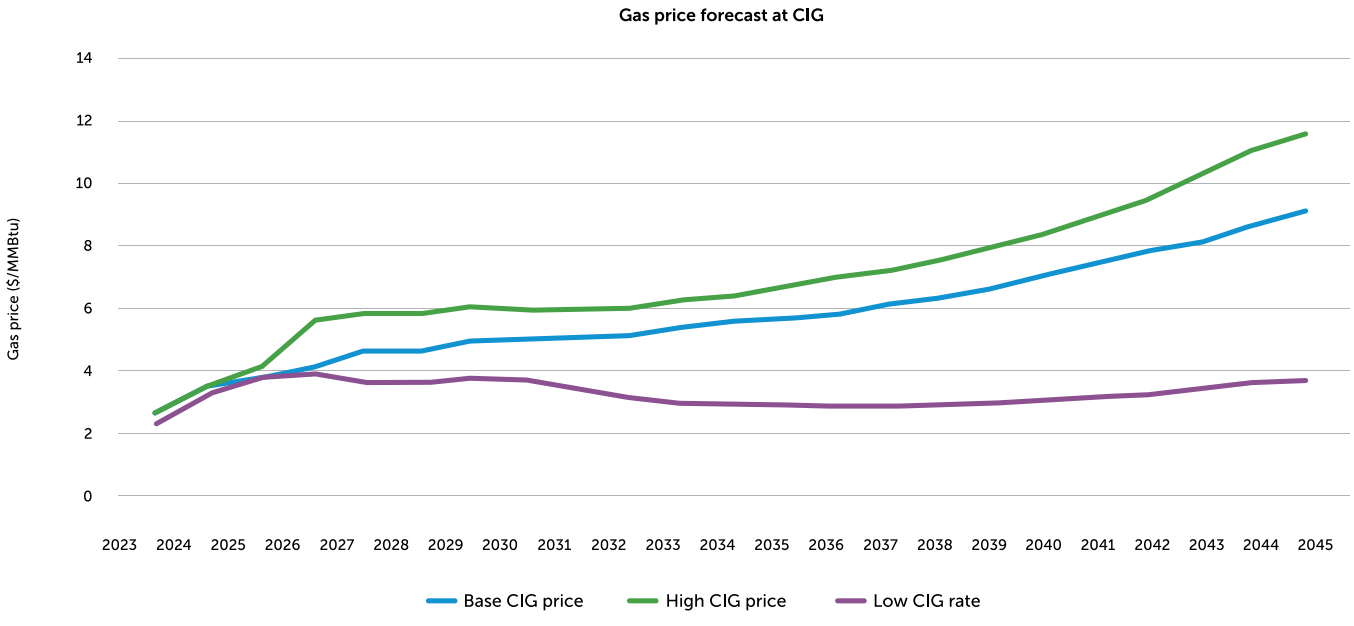



**Figure 39.** *Gas price forecast at CIG*

In addition to the above gas commodity prices, Platte River also pays transportation for natural gas delivered to the Rawhide site. Charges begin at $1.05/MMBtu for 2024, based on actual expenses, and increase at the assumed inflation rate.

Analysis assumes additional gas-related cost for gas pipeline reservation to improve the reliability of gas supplies after coal retirements. Actual gas supply cost varies depending on consumption levels, but an average cost to firm gas supply ranges from $35/kw-yr to $50/kw-yr for different gas units. These costs begin in 2030 and end in 2040, when the models assume the units switch to 100% green hydrogen. To improve fuel supply reliability, we will analyze options for firming up gas supplies, such as on-site storage or constructing an additional pipeline to the Rawhide plant site.

## 6.1.2 Green hydrogen prices

Green hydrogen as a noncarbon-emitting fuel for traditional gas turbines has potential in the future, as technological and economical barriers for storing and transporting hydrogen diminish. Based on the recommendations from Black & Veatch, Platte River assumed a 50% blend of hydrogen with natural gas in 2035 and use of 100% hydrogen in 2040. Future hydrogen pricing is uncertain; IRP modeling assumed 2035 hydrogen prices five times the prices of natural gas by 2035, decreasing to three times of natural gas by 2045. Hydrogen prices can be expressed in $/MMBtu or $/kg units. Price projections are shown in Figure 40.

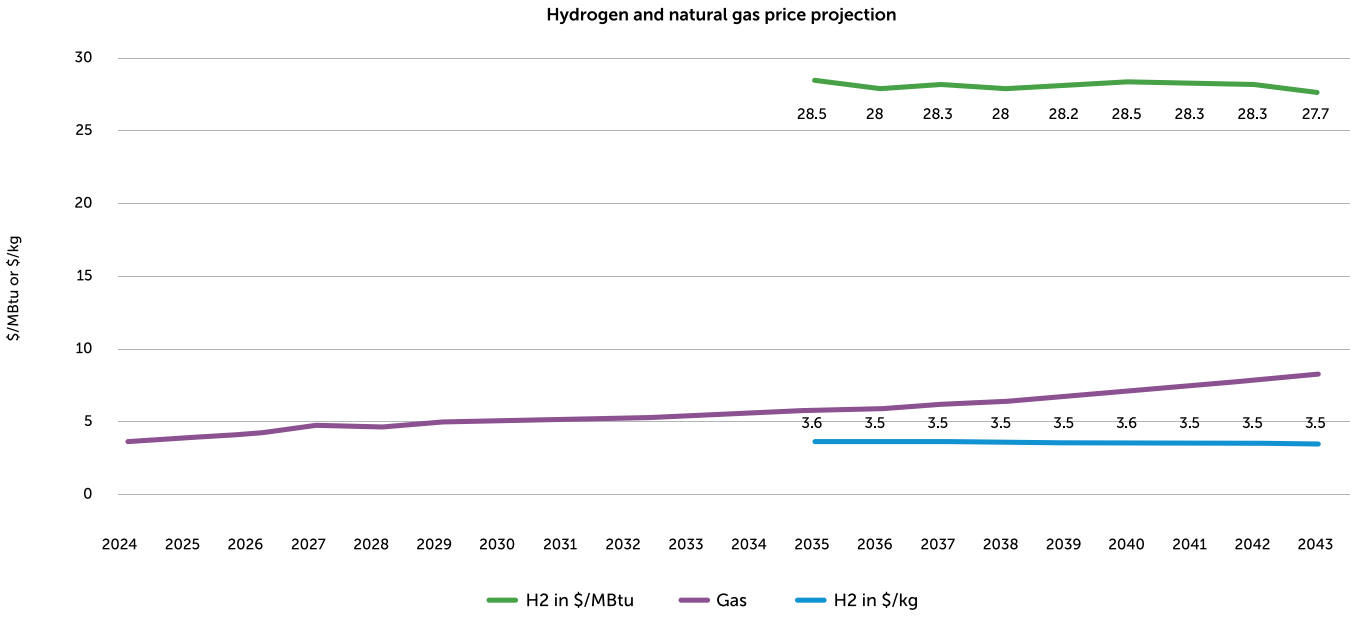



**Figure 40.** *Hydrogen and natural gas price projection*

## 6.1.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement. This means that price forecasts for Rawhide Unit 1 and the two Craig units are developed separately, as discussed below.

Rawhide receives coal from the Powder River Basin by rail and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier and near-term coal market assessments and indices. As locked-in quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2027, the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing. It includes additional costs for required dust suppressants and taxes passed through by the mine. Transportation expenses, based on the current rail rates projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 41 illustrates the delivered coal prices for Platte River coal plants.

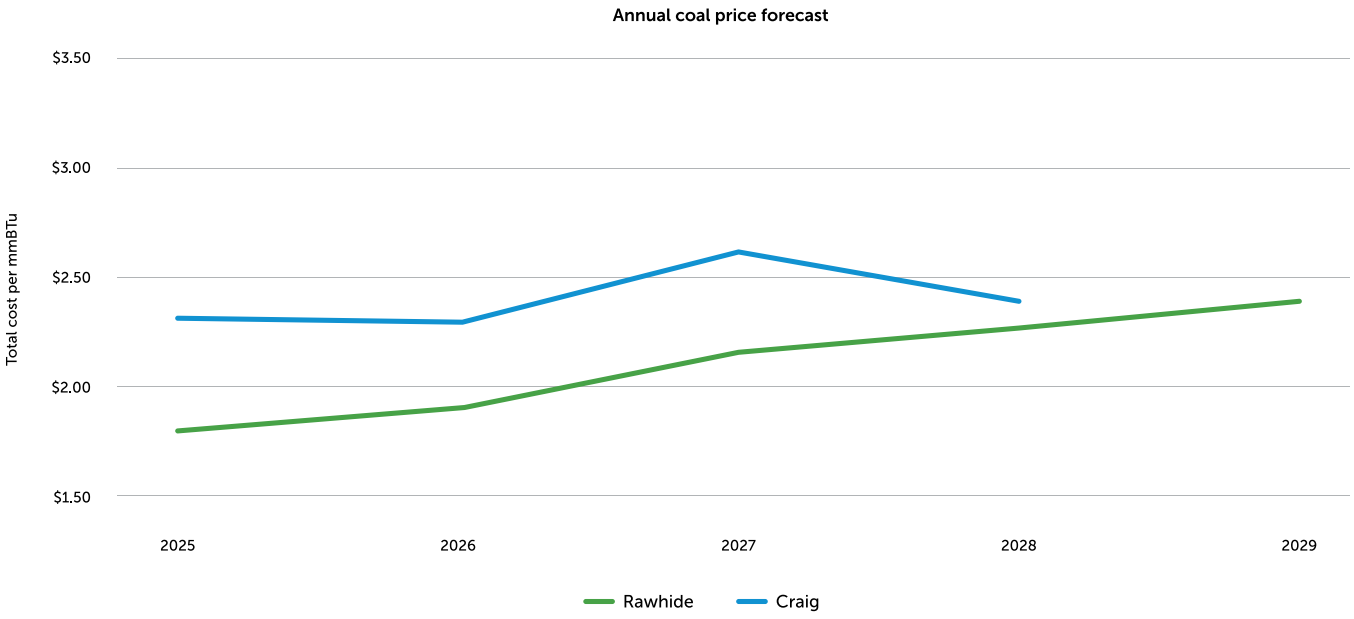



**Figure 41.** *Annual coal price forecast*

## 6.1.4 Regional power prices

Platte River's resources are dispatched in real time with resources from other utilities in the WEIS market to maximize economic exchange of power across the market. In addition to the real-time market, Platte River transacts with neighboring utilities bilaterally, selling excess power and buying power when needed. To simulate these bilateral transactions with neighboring utilities, resource planning models a regional market where Platte River can buy or sell when economical. Siemens has provided hourly future prices for Colorado area and these hourly prices are used in our simulations. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost of production and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Net revenues from market transactions reduce the overall cost of providing power to Platte River's owner communities.

With more renewable resources on the regional grid, renewable energy becomes a bigger driver of power prices. Siemens predicts that average annual power prices will remain relatively stable over the 20-year planning horizon. However, daytime prices (labeled as "on-peak solar" prices in Figure 42) will decline as more solar generation is added.

Figure 42 shows our current forecast for on-peak and off-peak power prices, including solar and non-solar hours. The model defines on-peak hours as Monday-Saturday from 6 a.m. to 10 p.m., with on-peak solar 8 a.m. to 5 p.m. every day and on-peak non-solar 5 p.m. to 10 p.m. Monday-Saturday. Off peak hours are 11 p.m. to 5 a.m. Monday-Saturday and all day Sunday. As shown in Figure 42, on-peak non-solar prices (representing the evening hours) stay the highest and on-peak solar, which reflect the day and time when solar is plentiful, are the lowest prices.

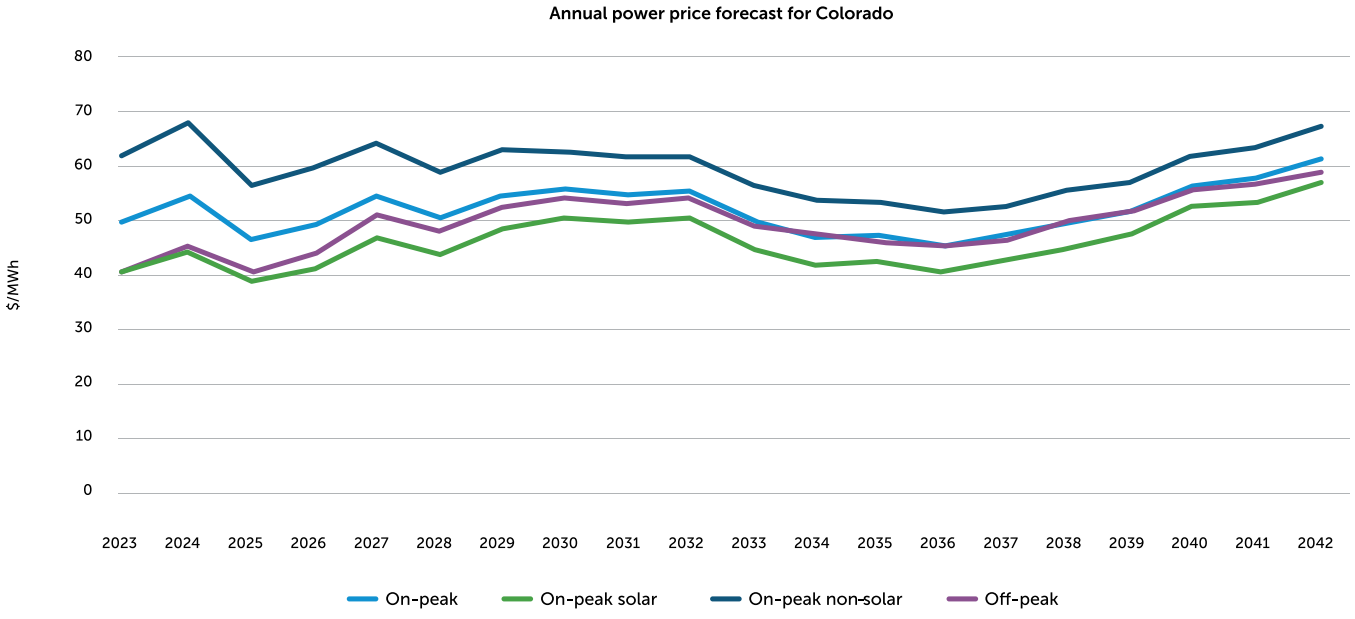



**Figure 42.** *Annual power price forecast for Colorado*

For the 2024 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped correlate relationships between market prices and energy production from the intermittent wind and solar resources. Siemens also provided the natural gas and emission prices forecasts, which were appropriately correlated to an hourly level in the IRP assumptions to ensure internal consistency among various projections.

### 6.1.5 Carbon taxes embedded in projected energy prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation. A carbon tax will discourage carbon emissions.

Platte River also evaluated portfolio outcomes using a social cost of carbon. The social cost of carbon simulates total direct and indirect (such as healthcare or extreme weather events) cost to the society from continued CO2 emissions. The social cost of carbon projection was based on the guidance of the Colorado Air Quality Control Commission, which valued the social cost of carbon at $68 per short ton in 2020 with an escalation rate of 2.5%, as shown in Figure 43.

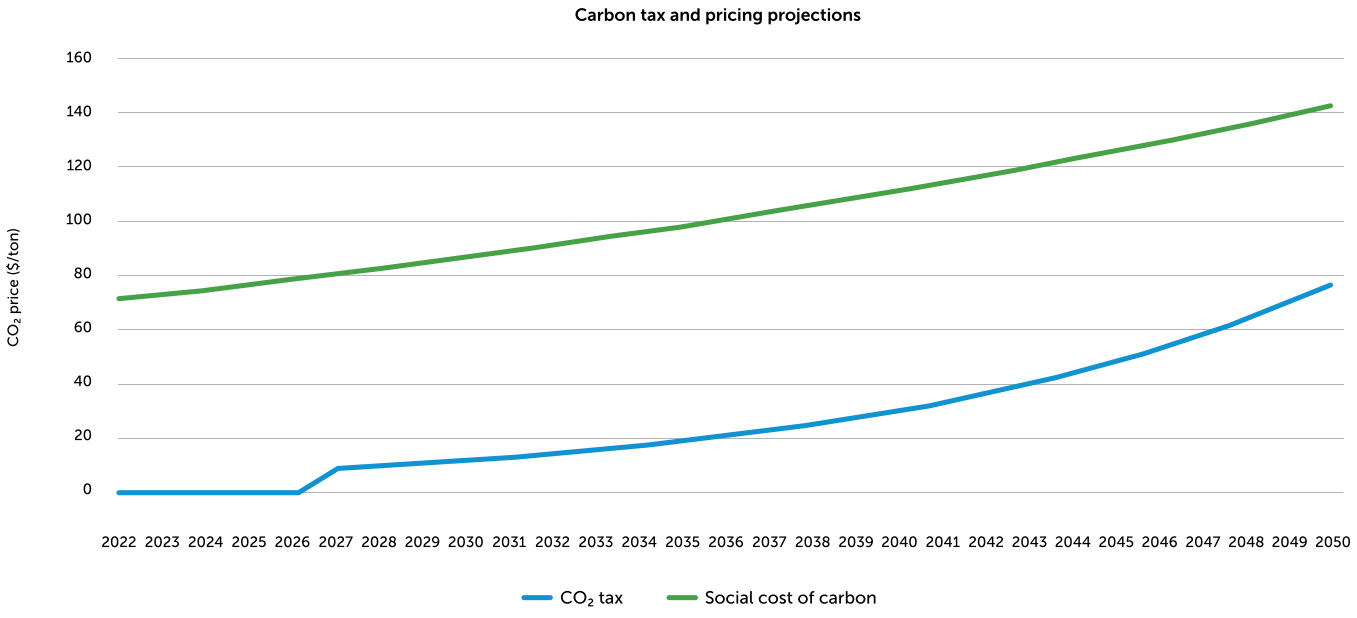



**Figure 43.** *Carbon tax and pricing projections*

## 6.2 Regional import/export limits

Platte River joined the WEIS market in April 2023, where Platte River's generation resources are jointly dispatched along with generation resources of other market participants to minimize dispatch costs for all market participants. When it joins SPP RTO West, Platte River will serve its load with a combination of owned resources and lower-cost resources from other market participants, implying real-time power sales and purchases with other RTO members. In addition, Platte River will continue bilateral transactions with regional entities, marketing excess energy through short- and long-term transactions. For IRP modeling, analysts assumed purchases or sales up to 150 MW in any hour. The 150 MW import/export limit means that market transaction volume remains realistic and that Platte River builds enough reliable energy generation to meet customers' needs and planning reserve margin requirements.

## 6.3 Supply-side generation resources

This section discusses all power generation resources Platte River considered to meet its customers' future electricity needs, beginning with our existing resources followed by committed resources. We then discuss additional future resources and the screening process to select candidate resources. A detailed discussion follows concerning the resources (both renewable and traditional) that Platte River is evaluating for future investment.

### 6.3.1 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed and community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or with an owner community's distribution utility. For modeling purposes, they function as resources that serve community load. Tables 10-15 list Platte River's existing resources.

| Coal generation facilities | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation | Nominal retirement / contract expiration |
|---|---|---|---|---|
| Rawhide Unit 1 | 280 | 280 | 1984 | 2029 |
| Craig Unit 1 | 77 | 77 | 1980 | 2025 |
| Craig Unit 2 | 74 | 74 | 1979 | 2028 |

**Table 10.** *Platte River's existing coal resources*

| Natural gas (simple-cycle CTs) generation facilities | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Rawhide Unit A | 65 | 65 | 2002 |
| Rawhide Unit B | 65 | 65 | 2002 |
| Rawhide Unit C | 65 | 65 | 2002 |
| Rawhide Unit D | 65 | 65 | 2004 |
| Rawhide Unit F | 128 | 128 | 2008 |

**Table 11.** *Platte River's existing natural gas resources*

| Contracted wind resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Medicine Bow | 6 | 1 | 1998 |
| Silver Sage[11] | 12 | 2 | 2009 |
| Spring Canyon I[12] | 32 | 5 | 2014 |
| Spring Canyon II | 28 | 6 | 2014 |
| Roundhouse | 225 | 39 | 2020 |

**Table 12.** *Platte River's contracted wind resources*

| Contracted hydropower[13] resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Loveland Area Project | 30 | 30 | 1973 |
| Colorado River Storage Project | 60 | 48 | 1973 |

**Table 13.** *Platte River's contracted hydropower resources*

| Contracted solar resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Commercial solar power purchase program | 4 | 2 | Approved 2013 |
| Fort Collins community solar | 1 | 0.4 | 2015 |
| Foothills Solar (Platte River share) | 0.5 | 0.2 | 2016 |
| Rawhide Flats | 30 | 17 | 2016 |
| Rawhide Prairie | 22 | 12 | 2020 |

**Table 14.** *Platte River's contracted solar resources*

| Contracted storage resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Rawhide Prairie Battery | 1 MW x 2 hours | 1 | 2020 |

**Table 15.** *Platte River's contracted storage resources*

[11] Silver Sage wind has been sold through 2029, when its PPA with Platte River expires. It does not return as a resource.

[12] Both Spring Canyon resources were sold in 2020 through 2030. They will return to Platte River in June 2030 and serve Platte River customers for the remaining term of their contract (through 2039).

[13] Estimated effective capacity due to persistent drought conditions throughout the West.

## 6.3.2 Committed or expected resources

This category includes resources for which either a final contract has been signed or negotiations are ongoing. These resources are treated like existing resources. These resources are included in modeling as assumed available and not subject to change through the optimization and resource selection process. These resources are shown in Table 16.

| Committed resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation | Current status |
|---|---|---|---|---|
| **Solar** | | | | |
| Black Hollow | 150 | 31 | 2025 | PPA signed |
| New solar | 150 | 24 | 2026 | Negotiations ongoing |
| **Storage** | | | | |
| Community battery | 25 MW x 4 hours | 18 | 2026 | Negotiations ongoing |

**Table 16.** *Committed resources*

## 6.3.3 Future candidate resources

Platte River selected future candidate generation resources by reviewing data from credible public sources, its consultants and its own market intelligence as detailed below. This section provides an overview of data sources, selection process and details of the selected resources.

### 6.3.3.1 U.S. Energy Information Administration

The EIA publishes cost and performance of new generation every year in its annual energy outlook report. The EIA report[14] is comprehensive and covers state of the art in traditional, low-carbon and renewable power generation technologies. We selected the following technologies from this report for further evaluation:

- Onshore wind
- Solar photovoltaic
- Battery storage
- Aeroderivative combustion turbine
- Reciprocating internal combustion engine
- Carbon sequestration
- Modular nuclear
- Geothermal

Planning staff screened out the following technologies from this report, as they are not suitable for Platte River's future power supply portfolio.



- Coal with or without carbon sequestration
- Combined cycle with or without carbon sequestration
- Large nuclear
- Offshore wind
- Biomass
- Solar thermal
- Conventional hydro
- Fuel cells

### 6.3.3.2 Black & Veatch consulting support

In addition to the resources considered from the EIA report, Platte River engaged Black & Veatch[15] to assess the landscape of low- and no-carbon fuels, energy storage and dispatchable power generation technologies. The Black & Veatch report assessed the availability of these technologies for 2028 commercial operation. For technologies not available for 2028, they estimated their future costs and commercial availability in the next decade. Black & Veatch reviewed the following options:

- **Biofuels.** The study concluded biofuels for power generation are not a viable option at Rawhide due to limited fuel availability and significant modifications required in the equipment to burn this fuel. Biofuels are better suited for transportation applications, rather than large power generation.

- **Hydrogen** – both green and blue. Green hydrogen is produced by an electrolyzer using renewable electricity, while blue hydrogen is produced from natural gas and the CO2 produced in the process is sequestered and stored in the ground. Hydrogen can be used as fuel in traditional power generation machines like CTs with some modifications. But there are significant technoeconomic challenges to store and transport hydrogen. The study concluded that green hydrogen could be a viable option for Platte River starting in the middle of the next decade.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[15] Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at prpa.org/2024irp/information.

- **Renewable natural gas.** Renewable natural gas is produced mostly at landfill or biowaste locations. The study concluded that renewable natural gas for power generation at the Rawhide site is not a viable option due to limited fuel availability. This fuel is better suited for small power generation at or near locations where the fuel is produced, such as landfill or wastewater treatment sites. Another possible use of renewable natural gas is for transportation, like the City of Longmont using renewable natural gas from its wastewater facility in the waste services truck fleet, displacing the use of diesel fuel. In some cases, renewable natural gas can be refined enough to meet the pipeline quality natural gas standard and can be pumped back into the gas network.

- **Ammonia.** Since transporting hydrogen over long distances is technologically and economically challenging (because hydrogen is a very light-weight molecule), industry is considering converting hydrogen into ammonia and then transporting it. At the destination, ammonia can be used directly in power generation or converted back to hydrogen and then used. The study concluded ammonia for power generation is not a viable option. It is better suited for transportation applications, rather than large-scale power generation.

- **Carbon capture and sequestration.** Carbon capture and sequestration technology was considered for removing CO2 from the existing combustion turbine units at the Rawhide site. The study concluded carbon capture and sequestration is not a viable option at Rawhide due to high cost of CO2 removal in peaking units (like those at Platte River, where combustion turbines are expected to run less than 20% of the time), and lack of known places to sequester CO2. Carbon capture and sequestration technology is a better option for baseload applications, where the generation source is running continuously and where the large capital cost can be spread over numerous tons of removed CO2. Additionally, carbon capture and sequestration technology is in the early commercial stages of development, with few proven and successful applications for power generation.

- **Long duration energy storage.** The study concluded that long-duration energy storage is an emerging technology, but not ready for commercial operation in 2028. This technology has potential and may become commercially available by the middle of the next decade. Platte River decided to plan for a 10 MW pilot long-duration energy storage project by 2030 and assume the technology would be available for commercial applications by 2035.

- **Flexible and low CO2 emitting thermal power generation.** In addition to the low- or no carbon emitting power generation options discussed above, the study reviewed various traditional combustion turbine and reciprocating internal combustion engine technologies that are flexible, reliable, efficient and hydrogen-capable. Three key future dispatchable technology requirements will be reliability, flexibility, and the ability to provide power for at least one week during dark calms. Because low or no-carbon options were not commercially available, the study recommended using gas-fired combustion turbines or reciprocating

internal combustion engines for commercial operation in 2028 and progressively converting to green hydrogen when it is economically available in large quantities. Combustion turbine and reciprocating internal combustion engine vendors claim that these machines will be capable of burning about 30% hydrogen by 2028.

### 6.3.3.3 Platte River's own market intelligence

Plate River's portfolio integration team monitors markets and collects information informally and formally through requests for information and requests for proposals. This engagement informs Platte River of the latest technology and pricing trends in the area. EIA, Annual Technology Book (ATB) or consultants can provide market trends and average prices, but the real prices for our area are available only through engagement with developers and vendors. Platte River conducted a solar and storage RFP in 2022 and started a wind RFP in 2023. These market interactions were valuable for collecting information about the projects being developed in our region—their costs, locations, schedules and technologies. This information was used to input costs of renewable and storage technologies in IRP modeling.

### 6.3.3.4 NREL's Annual Technology Book

NREL provides cost, efficiency and technology improvement trends of renewable and storage technologies in the ATB every year. We used the data in the 2022 ATB for this IRP, as it was the latest available in the spring of 2023 when staff finalized assumptions.

After a detailed review of all the sources mentioned above and internal deliberations, Platte River decided the following:

- For wind, solar and four-hour storage costs, we used our own market intelligence data for early year prices where data was available from multiple vendors.
- After the first three years, we used cost escalation and efficiency improvement rates proposed by the ATB.
- Actual cost data used for each technology is shown in the following sections.

For dispatchable resources, Platte River relied on the recommendations of Black & Veatch. Platte River decided the best option is to use highly flexible, state-of-the-art, hydrogen-capable aeroderivative combustion turbine technology. These machines will initially use natural gas fuel and by 2035 may start using 50% green hydrogen blend and by 2040 may use 100% green hydrogen. The process of selecting aeroderivative technology is discussed in section 6.3.7.

## 6.3.4 New wind resources

While wind resource availability within Platte River's service territory is limited, wind is abundant to the north and the southeast. Most likely, our future wind will come from southeast Wyoming or eastern Colorado. We have assumed that the southeast Wyoming wind will be delivered to Platte River through existing transmission capacity that will become available after retirement of Craig coal generation.



Eastern Colorado wind would be delivered through a neighboring transmission system at a cost of $6/MWh in 2023 and escalating with inflation. Because the existing transmission infrastructure in southeast Wyoming is limited, only 200 MW of wind is expected to be procured without incremental transmission cost. Any future wind will include a transmission charge or new transmission infrastructure at an assumed cost of $6/MWh.

New wind resources are assumed to be procured under PPAs for 100 to 200 MW blocks. PPA payments compensate the developer or the owner for capital costs (depreciation and returns), financing costs, interest during construction, taxes (sales, property, and income) and ongoing operating and maintenance costs. PPA prices for wind are based on recent quotes from project developers in the region. We assumed future wind prices will escalate based on the 2022 ATB future wind cost curves.

Southeast Wyoming wind is assumed to have an average annual capacity factor of 42.5%, while the eastern Colorado wind was modeled with a 45% capacity factor.

Wind projects (existing or new) carry ancillary service charges through 2025. Beyond 2025, we assume those costs cease with entry into a regional market. The combined cost of wind ancillary services in 2024 were modeled at $1.24/kw-mo.

Figure 44 shows wind costs for the two locations along with solar costs. As mentioned earlier, PPA prices are generally fixed for their terms (typically 20-30 years). Figure 44 assumes that for 2026, the southeast Wyoming wind PPA price will be fixed at $35/MWh for the PPA term, while for the wind PPA signed in 2030, it will cost $33.65/MWh for the life of the project.

### 6.3.5 New solar resources

New solar resources were considered as 50 MW block sizes priced at a 30-year levelized PPA payment, including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Platte River received solar price data based on recent RFPs and negotiations with developers. These prices were escalated with NREL's 2022 ATB solar cost projections.

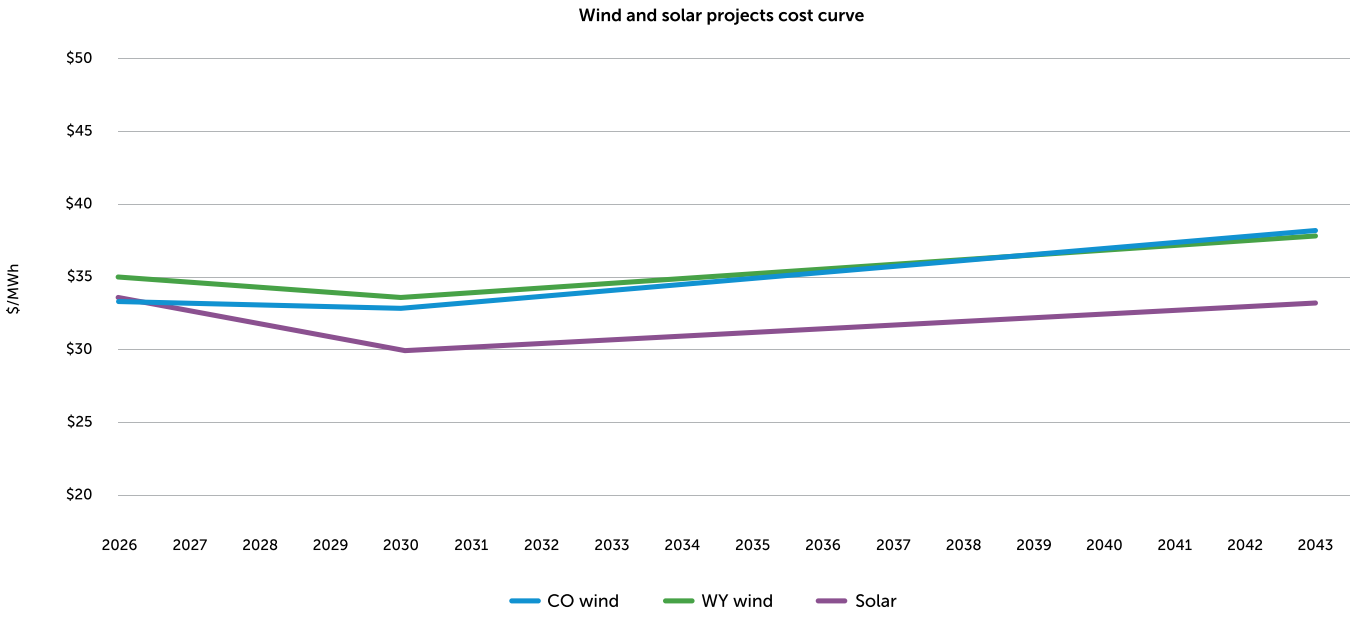



**Figure 44.** *Wind and solar projects cost curve*

Platte River assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Solar ancillary service costs in 2024 were assumed at $0.09/kw-mo.

## 6.3.6 New storage resources

Energy storage is the keystone in a deeply decarbonized power supply portfolio. A 100% renewable power supply portfolio using wind and solar as the main source of energy will need energy storage from a few seconds to several days to complement supply intermittency. Platte River considered a variety of different commercially available battery storage technology options, including lithium-ion batteries for four-hour storage duration, flow batteries for 10-hour storage duration and long-duration energy storage batteries for 100-hour storage duration. These battery types will provide different services to support the grid while complementing renewable intermittency.

Four-hour lithium-ion battery technology is mature and commercially available. We assumed 200 MWh of storage per 50-MW four-hour battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Four-hour batteries were assumed to have an 85% round trip storage efficiency. The economic life of a four-hour battery was modeled to be 20 years. Like wind and solar, 2024 prices for four-hour battery storage were based on the recent RFP and vendor negotiations. Future prices escalate based on the 2022 ATB. See the cost projections in Figure 45.

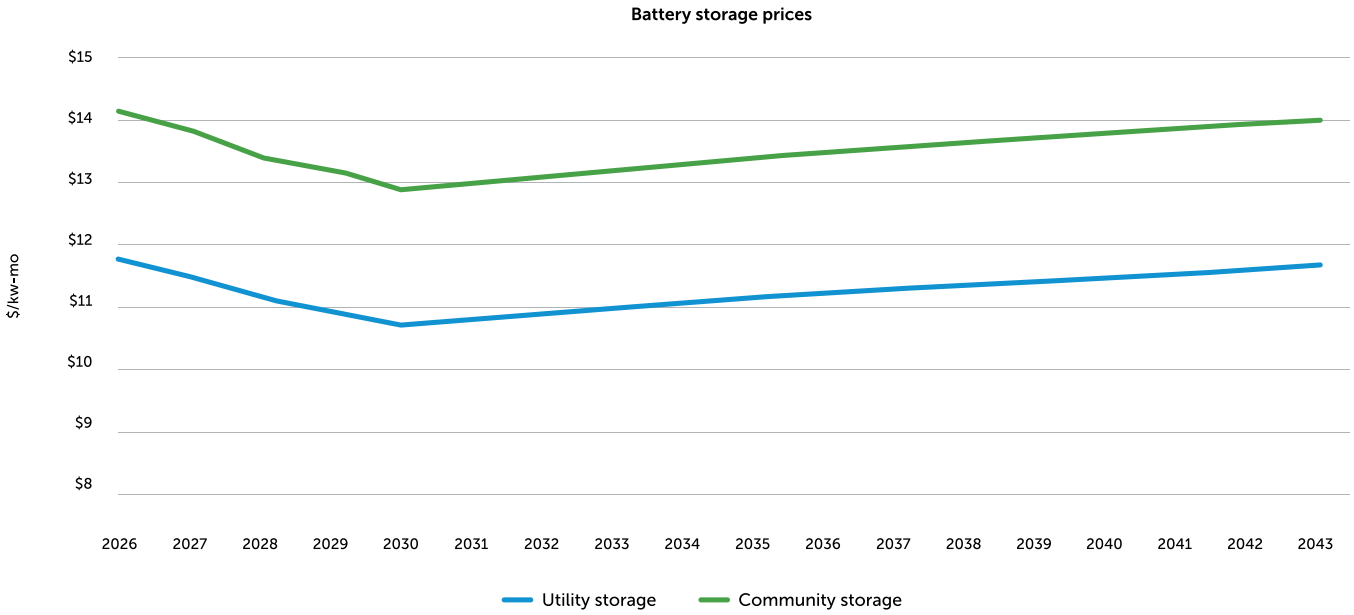



**Figure 45.** *Battery storage prices*

Ten-hour flow batteries are an emerging technology with no existing commercial installations as of 2023. We worked with a vendor to get cost, efficiency, and performance details. Based on the data provided by the vendor, this technology was not found to be economical during our early technology screening and minimal cost portfolio development process. Therefore, this technology was not considered as a resource in the IRP. However, this technology has potential to become part of the future power supply portfolio. As the technology matures, Platte River will consider it.

Long-duration energy storage is critical for supplying power during extended dark calm periods. Like flow batteries, this technology is also under development with no existing commercial installations as of 2023. Platte River analyzed the cost, efficiency, and performance details of long-duration energy storage. When fully developed and commercialized, long-duration energy storage will reduce the need for fossil generation to provide backup power and reliability in a renewable portfolio. Platte River plans to integrate a 10 MW pilot unit before 2030. For IRP modeling, we assumed that the technology will be commercially available by 2035. The current capital cost of this technology is high, and the round-trip efficiency is low. We assumed cost reduction and performance improvements over time as the technology matures and finds commercial applications.

### 6.3.7 New dispatchable thermal generation resources

As mentioned earlier, after a thorough review of all the options for no- or low-carbon fuels, and for dispatchable generation technologies, Black & Veatch recommended Platte River use natural gas-fired generation for 2028 commercial operation and then convert to green hydrogen fuel when it is commercially available. Platte River and Black & Veatch looked at 50+ options and screened down to the seven listed in Table 17 for detailed assessment.

| Characteristic | Unit | LM2500 | LM600 | LMS100 | RICE | 7F CC conver-sion | LM600 CC | SGT800 |
|---|---|---|---|---|---|---|---|---|
| Unit size | MW | 28 | 40 | 90 | 17 | 17-116 | 31-44 | 55 |
| Heart rate | btu/kWh | 9,875 | 9,649 | 8,820 | 8,510 | 6,646 | 7,087 | 9,707 |
| Cost per MW | $M/MW | $1.8 | $1.7 | $1.2 | $1.7 | $2.2 | $2.3 | $1.4 |

**Table 17.** *Screened dispatchable technologies*

LM2500, LM6000 and LMS100 are aeroderivative CTs manufactured by General Electric. RICE is reciprocating internal combustion engine. The next two were combined cycle options; converting the existing 7F CT at Rawhide station or install 4 LM6000 CTs with combined cycles. Finally, SGT800 is a combination of frame and aeroderivative technologies manufactured by Siemens.

After analyzing the levelized cost of energy and reviewing operational characteristics of the seven technologies, a smaller group of four featured in Table 18 was selected for more detailed assessment. These four technologies were further analyzed in detail for characteristics like reliability, emissions, economic value, operational flexibility, fuel versatility, constructability and market performance. During this detailed evaluation, higher weights were assigned to the factors aligned with Platte River's three pillars of reliability, environmental responsibility and financial sustainability. This analysis concluded that aeroderivative technology was the best option for Platte River. The LM6000 technology was selected as the presumed technology for inclusion in the supply portfolio.

| Qualification | Weight | Option 1 | Option 2 | Option 3 | Option 4 |
|---|---|---|---|---|---|
| Reliability | 30% | 1.52 | 2.52 | 2.7 | 1.51 |
| Emissions | 25% | 0.7 | 2.41 | 2.34 | 1.69 |
| Costs | 20% | 1.55 | 1.47 | 1.55 | 2 |
| Operational flexibility | 10% | 0.9 | 0.91 | 0.88 | 0.8 |
| Fuel versatility | 5% | 0.05 | 0.36 | 0.36 | 0.42 |
| Constructability | 5% | 0.45 | 0.45 | 0.45 | 0.35 |
| Market performance | 5% | 0.4 | 0.5 | 0.45 | 0.45 |
| **Total weighted score** | **100%** | **5.57** | **8.62** | **8.72** | **7.21** |

**Table 18.** *Results of detailed screening of four selected technologies*

# 07 IRP design



# 7.1 Studies

The following studies support this IRP. All studies are available on the IRP microsite.

- PRM and ELCC study by Astrape Consulting
- Beneficial electrification forecast by Apex Analytics
- Distributed energy resources forecast and potential study by Dunsky
- Extreme weather events and dark calm analysis by ACES
- Independent review of dispatchable capacity needs by Black & Veatch
- Generation technology screening by Black & Veatch

Additionally, this IRP uses fundamental market analysis of supply and demand in the region provided by Siemens, and a locational marginal pricing assessment by ACES.

# 7.2 Objectives

The objective of this IRP is to continue Platte River's journey toward achieving the goals of the RDP by developing a roadmap to meet the owner communities' needs for reliable, environmentally responsible and financially sustainable energy and services using a diverse power supply portfolio.

# 7.3 Planning for a reliable future power supply

Power supply reliability is a key responsibility of a utility. It is a foundational pillar for Platte River's planning and operations. Platte River plans to join a full organized energy market in 2026, which will take over transmission planning and some operational responsibilities. In a market, a load-serving entity like Platte River is required to bring enough resources to reliably serve its load according to the reliability criteria enacted by the market operator. Markets allow a wider access to improve economics and reliability under varying weather and operating conditions, but they do so by relying on the resources contributed by each market participant. This chapter covers reliability modeling in the IRP and the development of different power supply portfolios to cover a wide range of future possibilities.





## 7.3.1 Power supply reliability

As society's dependence on electricity increases, power supply reliability is becoming more critical. Electric reliability is not only the foundation for commerce; our security and safety depend on it. This critical dependence became tragically clear when Texas power outages during Winter Storm Uri caused 246[16] deaths and billions of dollars in economic losses.

Power supply reliability is the ability of a power system to keep the lights on under changing supply and demand conditions. Electric utilities must plan, design, construct and operate an electric supply system for reliability of supply.

There are a few terms used under the broad umbrella of reliability:

- Adequacy is a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, considering scheduled and unscheduled outages of system components.
- Security is the ability of the power system to withstand disturbances.

[16] Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

[17] https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages



- Resilience is the ability to quickly adapt and recover from a disruption, with minimal impact.

Historically, threats to power supply reliability included equipment failure (at the distribution, transmission, or generation level) or extreme weather like hurricanes, floods, snowstorms and heat storms. More than 90% of the power supply interruptions or reliability events can be attributed to breakdowns in the distribution system.[17]

Distribution system interruptions are typically localized and affect a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are broader reaching and potentially more consequential. With increased reliance on wind and solar generation in the future, an additional threat to reliability will be low or no production from these intermittent resources for extended periods.

In our IRP process, Platte River focuses on reliable, environmentally responsible and lowest reasonable cost power supply portfolios. Some of the major variables that drive power supply reliability in our planning process are:

- Occasional generation equipment failures
- Load forecast uncertainty
- Variability of hourly wind and solar generation patterns
- Occasional extreme weather (such as heat or cold waves)
- Extended periods of low or no renewable generation

After an extensive review of hourly generation profiles of solar and wind, we found that there are certain times when there is very little or no renewable generation for extended periods. We call these incidents dark calms. We have found that dark calm events occur frequently and can last from a day to as long as seven days.

While our definitions of reliability and related concepts are general, over the years the power industry has developed specific metrics and methods to plan for a reliable supply portfolio as discussed in the next section. A starting point for developing a reliable power supply is a resource adequacy study. This study simulates a future power supply portfolio under varying conditions of power supply and power demand to assess its reliability.

## 7.3.2 Planning for a reliable future portfolio

### 7.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, defines requirements for resource adequacy in Standard BAL-502-RFC-02.[18] This standard requires utilities to "calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1." This metric is also referred to as Loss of Load Expectation (LOLE) of 0.1 per year or LOLE of one day in 10 years, or sometimes, as "One Day in Ten Years" (ODTY). This metric has been widely used in planning studies since the early days of modern power systems.[19]

This metric has traditionally guided investment in generation to provide reliability accepted as the optimal target. Historically, ODTY or 0.1 day LOLE per year has required utilities to maintain a 10-15% PRM. PRM is defined as the percent additional firm capacity relative to the peak demand in a future year. Specifically,

$$\text{PRM} = \frac{\text{Firm capacity - peak demand}}{\text{Peak demand}}$$

Historically, PRM covered planned or unplanned outages (equipment breakdowns) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provides



firm capacity) over the past decade, and with the introduction of intermittent renewable generation resources, the structure of power supply portfolios is rapidly changing.

LOLE of 0.1 day per year is still the dominant metric in the power industry, but some alternatives are being proposed and debated.[20] The main criticism of 0.1 day LOLE per year metric is that this probabilistic calculation does not adequately measure the depth (how much power was lost, or how many customers lost power), breadth (how long power was lost) and the frequency (how often power was lost).

In a recent report,[21] EPRI summarized the existing and proposed metrics, arguing that a single metric such as ODTY may conceal some risks and may not be able to sufficiently capture



the future challenges to the power grid from:

- Rapid decarbonization of power supply with the retirement of dispatchable resources and adoption of intermittent renewables.
- Adoption of electrification in transportation and heating.
- Adoption of DERs with wider customer involvement.
- Climate change and extreme weather events.

With the introduction of renewable generation, the concept of planning for the "Peak Hour" of the year is giving way to planning for every hour in the year. The hour when the system experiences peak demand is less important than the load net of renewables. For example, Figure 46 from New York ISO[22] shows that typically they experience peak demand between 3-4 p.m. in July, but, due to solar generation, the net peak demand is lower and shifts to 5-6 p.m.

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

[19] https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf

[21] https://www.epri.com/research/products/000000003002023230

[22] https://www.nyiso.com/-/shaving-peaks-with-the-sun

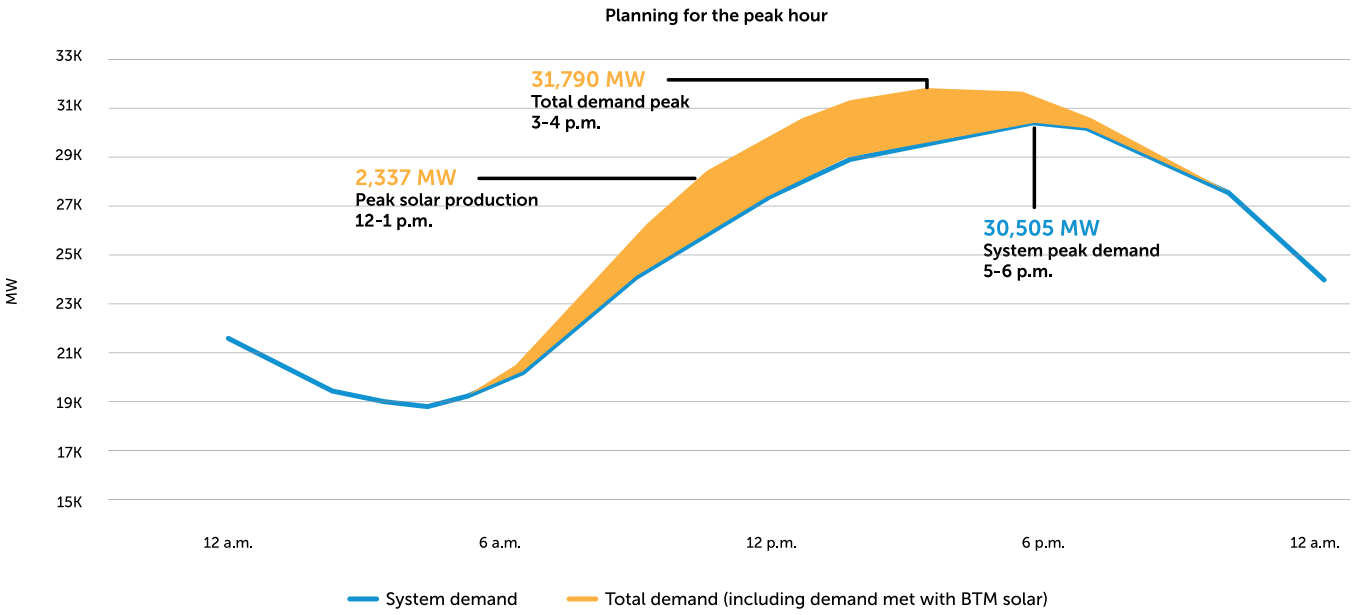



**Figure 46.** *Planning for the peak hour*

Other parts of the country experience similar phenomena. Wind generation may shift the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for reliability of the electric grid in 13 western states (including Colorado), is proposing to estimate resource adequacy for every hour, targeting an hourly LOLE of 0.002%.[23]

## 7.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as its reliability metric. With the changing portfolio mix in the region[24] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[25] study for this 2024 IRP. This study computed PRM and ELCC[26] of intermittent renewable resources, small amounts of energy battery storage and DERs. The study focused on the year 2030 and modeled the Platte River supply portfolio, along with other utilities in Colorado. The study assumed these utilities will develop the power supply portfolios projected in their respective IRPs and will be part of a functioning market. The study concluded that all Colorado utilities, including Platte River, would need a PRM of 19.9%. This value, though higher

[23] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default

[24] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO2 emissions by at least 80% from 2005 levels.

[25] https://www.prpa.org/wp-content/uploads/2023/11/2024IRP-PRM-and-ELCC-study-by-Astrape.pdf

[26] ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

[27] https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

than the 2020 IRP PRM of 15%, aligns with the WECC-recommended Planning Reserve Margin Index or Variability Margin Index in its 2023 Western Assessment of Resource Adequacy[27] report. Power markets like the Midcontinent Independent System Operator (MISO) and SPP are also looking at higher PRMs than previously recommended due to coal retirements and more intermittent energy integration.

Astrape's proposed PRM of 19.9% for 2030 incorporates its analysis of Colorado, utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, using their modeling platform Strategic Energy & Valuation Model, which is also used by major U.S. utilities and several regional power pools. Astrape modeled major uncertainties like weather by using 42 years of historical data for hourly wind, solar and load shapes, three to five days of dark calms, five scenarios of future load forecast error and 300 scenarios of generation availability, for a total of 63,000 simulation scenarios for each hour of the year 2030. This comprehensive analysis produced the relationship between LOLE and PRM as shown in Figure 47.

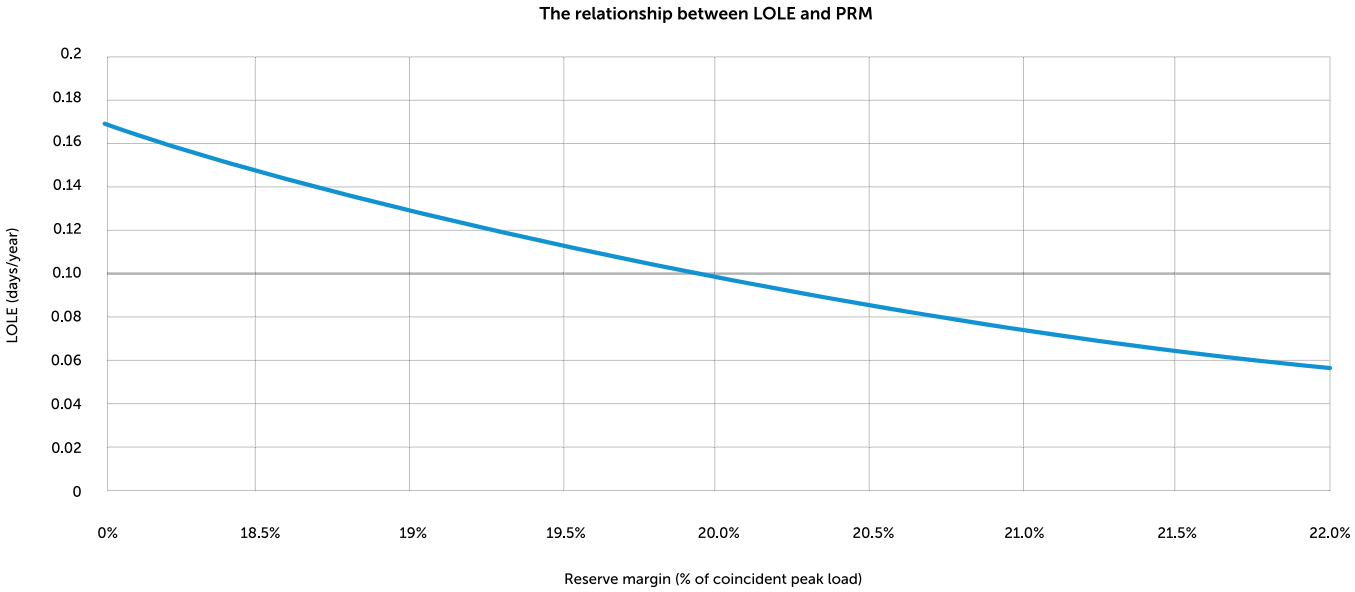



**Figure 47.** *The relationship between LOLE and PRM*

At 0.1 day LOLE per year, the PRM is 19.9%. If we were to build a more reliable system with a LOLE of 0.06, or one outage every 16 years, we will need a PRM of 21.8%. On the other hand, a LOLE of 0.16, with an expected outage every six years, would require a PRM of 18.4%. Essentially, the more spare capacity we have, the less likely we are to face a supply shortage or LOLE.

As mentioned earlier, EPRI recommends not relying on one metric. Utilities and other entities are considering many metrics. In addition to the PRM, we used Loss of Load Hours (LOLH) in our IRP modeling. LOLH measures the average duration of outages. We used LOLH 0.2 during reliability testing of our portfolios.

### 7.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy-limited resource measures its expected contribution to peak demand. For example, 100 MW from a coal or gas fired plant can provide 100 MW at the time of peak. When running at full load, it will reduce the peak load by 100 MW. The ELCC of this resource is 100 MW or 100%.

But 100 MW of wind, solar or four-hour storage may or may not be able to provide 100 MW at system peak. This means its ELCC will be lower than the nameplate capacity. This can be seen for solar generation in the example shown in Figure 48. It shows hypothetical hourly load and solar generation forecast for a summer day in 2030 for Platte River's system.

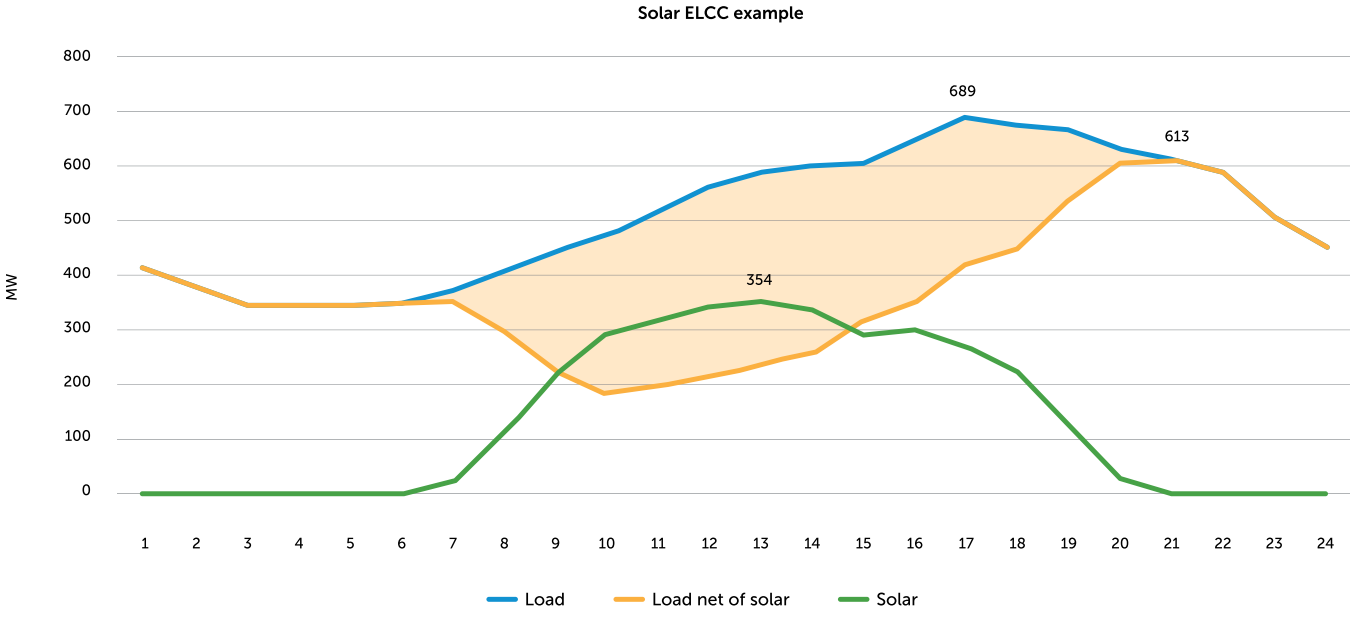



**Figure 48.** *Solar ELCC example*

The blue line shows hourly load for 24 hours across the day. The peak load during the day is 689 MW at hour 17 or 5 p.m. The green line shows solar generation. It starts around 6 a.m., peaks at 354 MW at 1 p.m. and drops to zero by 9 p.m. The orange line shows hourly load net of solar generation. Solar generation reduces the load by the shaded area. The orange line shows that the peak hour of the load has shifted from 5 p.m. to 9 p.m. and is 613 MW. So, the solar generation has reduced the peak demand by 76 MW (689 minus 613). While the maximum solar generation is 354, the nameplate of installed capacity of solar is 507 MW in this example. For this day, solar ELCC is 76/507=15%. In other words, installed capacity of 507 MW reduces the peak demand by 76 MW. Put another way, the effect solar had on the peak is that it reduced peak by 76 MW.

As we install more solar, its impact on reducing peak will be zero, because the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In that case, the incremental ELCC of solar after 507 MW is zero. This example shows just one hypothetical day. In reality, ELCC calculations are computed after thousands of simulations under different load and weather conditions.

ELCC of wind and other resources follows the same declining pattern with more resource additions. As more wind is added, the incremental contribution of the next wind project to reduce peak demand continues to decline. Figure 49 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape, which we used  for this IRP. As utilities in Colorado add more of these resources over time, their ELCC contributions diminish.

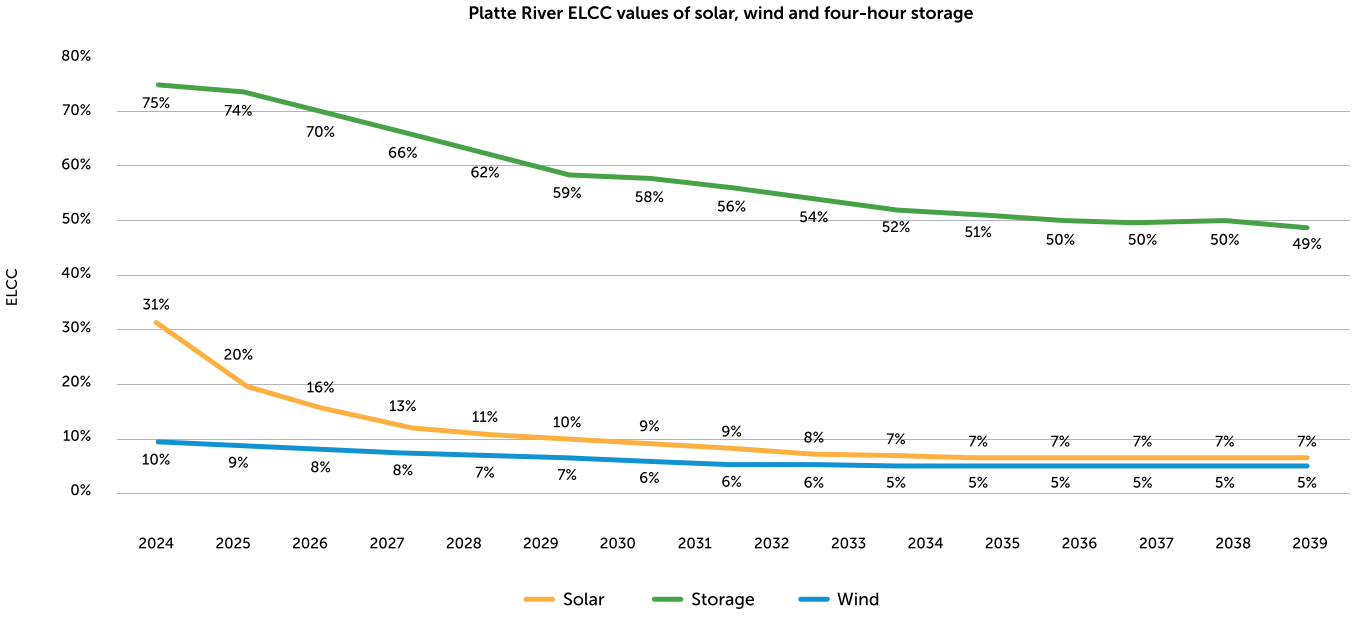



**Figure 49.** *Platte River ELCC values of solar, wind and four-hour storage*

Table 19 shows ELCC values of longer duration battery storage and some DER technologies, as computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces that resource type's ELCC. For example, the ELCC of distributed solar is 8.5% if Colorado utilities install 500 MW. It drops to 5.8% with 4,000 MW installed.

| Technology | Penetration (MW) | Average ELCC (%) | Marginal ELCC (%) |
|---|---|---|---|
| 8-hour batteries | 500 | 92.7% | 91.6% |
| 8-hour batteries | 1,000 | 90.5% | 84.4% |
| 8-hour batteries | 1,500 | 87.0% | 75.6% |
| 100-hour batteries | 500 | 92.7% | 91.6% |
| 100-hour batteries | 1,000 | 91.9% | 90.8% |
| 100-hour batteries | 1,500 | 91.4% | 90.0% |
| Distributed generation solar | 500 | 8.5% | 7.9% |
| Distributed generation solar | 1,000 | 8.0% | 7.2% |
| Distributed generation solar | 2,000 | 7.2% | 5.8% |
| Distributed generation solar | 4,000 | 5.8% | 2.9% |
| Beneficial electrification | 100 | 6.9% | 7.4% |
| Beneficial electrification | 200 | 7.3% | 8.2% |
| Beneficial electrification | 300 | 7.8% | 9.0% |
| Electric vehicles | 100 | 32.0% | 33.6% |
| Electric vehicles | 200 | 33.8% | 37.3% |
| Electric vehicles | 300 | 35.7% | 41.0% |
| Demand response | 100 | 92.3% | 87.3% |
| Demand response | 200 | 87.1% | 77.8% |
| Demand response | 300 | 82.6% | 70.4% |

**Table 19.** *ELCC values of long-duration energy storage and DERs*

## 7.3.2.4 Extreme weather and dark calm modeling

Winter Storm Uri, which brought blackouts to Texas and stressed power supply across a much wider area, also impacted power supply in our area. Due to extremely cold weather for many days, demand for electricity continued to rise. Additionally, there was very little renewable generation for almost 80 hours during Feb. 12-16, 2021, as shown in Figure 50.

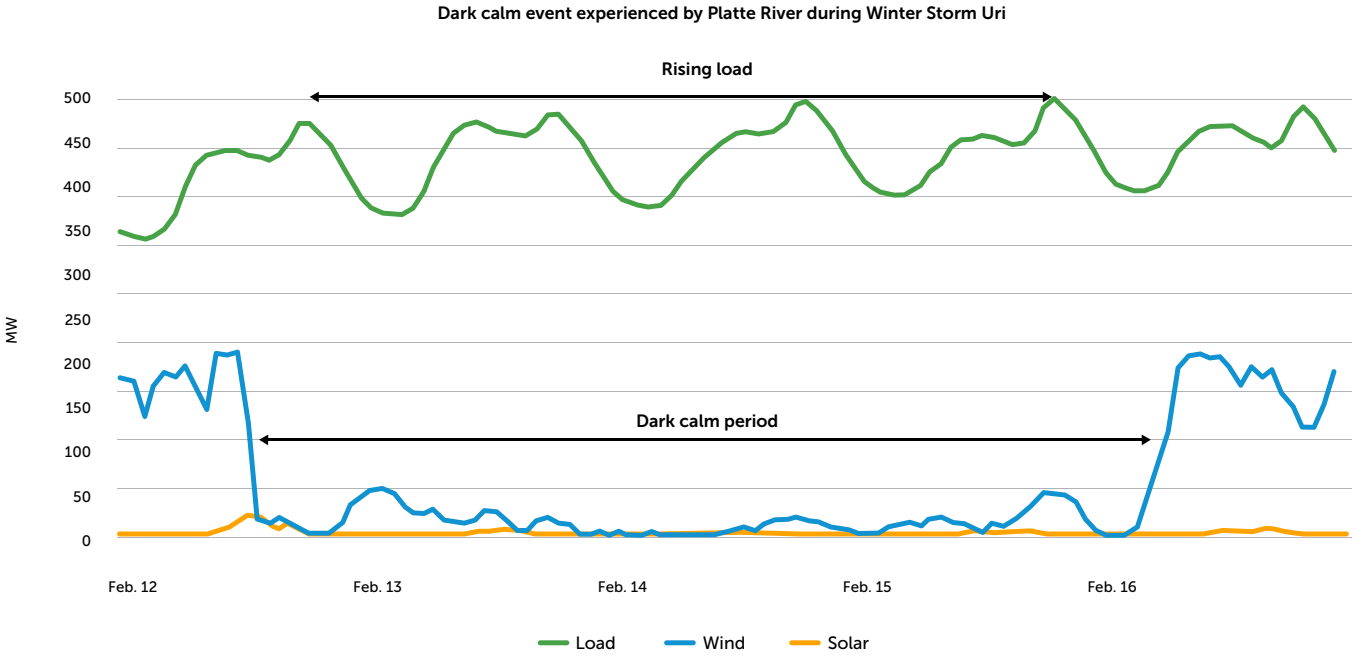



**Figure 50.** *Dark calm event experienced by Platte River during Winter Storm Uri*

During this 2021 dark calm, Platte River was able to serve its customers' load reliably because dispatchable coal resources were available. But after coal units retire in 2030, we may experience similar or even more severe dark calms. A fundamental requirement of an IRP is to develop supply portfolios that will be reliable under varying conditions of weather, previously experienced or not. This led us to hire ACES to conduct a study on extreme weather and dark calm events.[28]

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) to estimate the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES reviewed weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 51 shows locations of the airports where data was collected.

[28] https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).




**Figure 51.** *Locations of extreme weather events*

## 7.3.2.5 Extreme weather events

The study found the following durations and frequencies of heat and cold waves:

| Heat wave summary – west region | | | | | | |
|---|---|---|---|---|---|---|
| Number of hours | 48 | 72 | 96 | 120 | 144 | 168 |
| Events per year | 0.47 | 0.02 | 0.09 | 0.04 | 0.021 | 0.043 |

**Table 20.** *Heat wave summary - west region*

This means every other year, there is a heat wave lasting two days and every 11th year, there is a heat wave lasting four days.

| Cold wave summary – west region | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of hours | 48 | 72 | 96 | 120 | 144 | 168 | 192 | 216 | 240 | 264 | 288 | 312 | 336 |
| Events per year | 4.9 | 1.7 | 0.9 | 0.4 | 0.17 | 0.08 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Table 21.** *Cold wave summary - west region*

This data shows cold waves are more common with five two-day events every year and a weeklong event almost every 12th year.

The study also found that load, power and gas prices rise during these extreme events and noted these increases during winter storms Uri and Elliot and the 2020 summer heat wave in the Pacific Northwest. Because our focus with extreme weather modeling is on reliability, we assessed how extreme weather impacts load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load for that time of year. So, for reliability assessments during extreme weather, we increased the hourly load by 10%.

### 7.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the MISO North , covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Northwest portion of the Electric Reliability Council of Texas (ERCOT. Table 22 shows the frequency and duration of different levels of dark calm events.



| Dark calm events by location | | | | |
|---|---|---|---|---|
| % of full output | 48 hours | 72 hours | 96 hours | 120 hours |
| **MISO Central** | | | | |
| 5% | 3.0 | 1.25 | 0.5 | 0.25 |
| 10% | 11.2 | 5.6 | 2.4 | 2.0 |
| 15% | 6.2 | 11.4 | 3.8 | 4.8 |
| **MISO North** | | | | |
| 5% | 1.0 | 1.0 | 0.67 | 0.0 |
| 10% | 5.0 | 1.75 | 0.5 | 1.0 |
| 15% | 2.2 | 3.0 | 1.2 | 2.0 |
| **Northwest ERCOT** | | | | |
| 10% | 3.8 | 1.0 | 0.2 | 0.2 |
| 15% | 3.2 | 3.4 | 3.0 | 1.2 |

**Table 22.** *Dark calm events by location*

As shown in Table 22, a dark calm event in MISO Central, where the output of renewable drops to 5% of total generation occurs:

- Three times during the year for two days every year
- Once per year for three consecutive days
- Every other year for four consecutive days
- Every four years for five consecutive days

Dark calm events where output of renewables drops to 10% of total generation are more frequent than events where renewable generation is only 5% of total generation. Dark calm events are less intense and less frequent in MISO North and Northwest ERCOT.

In the Plexos model, we averaged the two 5% rows for MISO Central and MISO North. Multiplying the probability of an event's occurrence with its duration yields the expected outage hours in a given year for that event. For example, as illustrated in Table 23, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours because the events last two days.

Since the events are non-additive, we sum all the expected hours to find the total expected dark calm hours in a year. In this case, an average year would see a total of 248 hours of dark calm spread across events of different durations.

| Dark calm duration (hours) | 48 | 72 | 96 | 120 | Total dark calm hours |
|---|---|---|---|---|---|
| Average # of dark calm events across all regions (5% of full output) | 2.000 | 1.125 | 0.585 | 0.125 | |
| Expected dark calm hours per year | 96 | 81 | 56.16 | 15 | **248.16** |

**Table 23.** *Dark calm event duration and frequency*

### 7.3.2.7 Transmission planning

Platte River conducts annual transmission assessment studies to plan for a system that adequately supports both short and long-term load obligations to the owner communities. The studies use transmission network modeling software and integrate forecasted owner community loads, existing and planned generation, and loads and generation from neighboring utilities.

Short-term studies evaluate system needs under the current transmission network configuration, integrating projected short-term load and generation forecasts. Evaluating long-term transmission needs includes forecasting long-term load and generation forecasts with both the current transmission system and planned transmission additions.

The study objectives are for the transmission system to perform reliably during extreme contingency situations, heavy or light load conditions and fault events. If a study identifies network deficiencies, further analysis follows to determine network expansion options to mitigate those deficiencies. Transmission studies are conducted during annual internal assessment activities, along with collaborative studies with regional transmission planning committees.

## 7.3.3 Need for new resources

As explained in chapter 5, we forecast our future energy needs as annual peak demand (maximum demand in any hour) and total annual energy for every hour of the year. For supply-side planning, we adjust these values with DER contribution from our customers. The net peak demand and energy demand are what Platte River needs to plan for through this IRP process. As discussed earlier in this chapter, Platte River plans to meet its future peak demand with 19.9% PRM to protect supply reliability. We also discussed that renewable and energy limited resources contribute less ELCC capacity toward the peak demand than their maximum or nameplate capacity.

Figure 52 shows the capacity requirements and capacity contributions from the existing and committed resources.

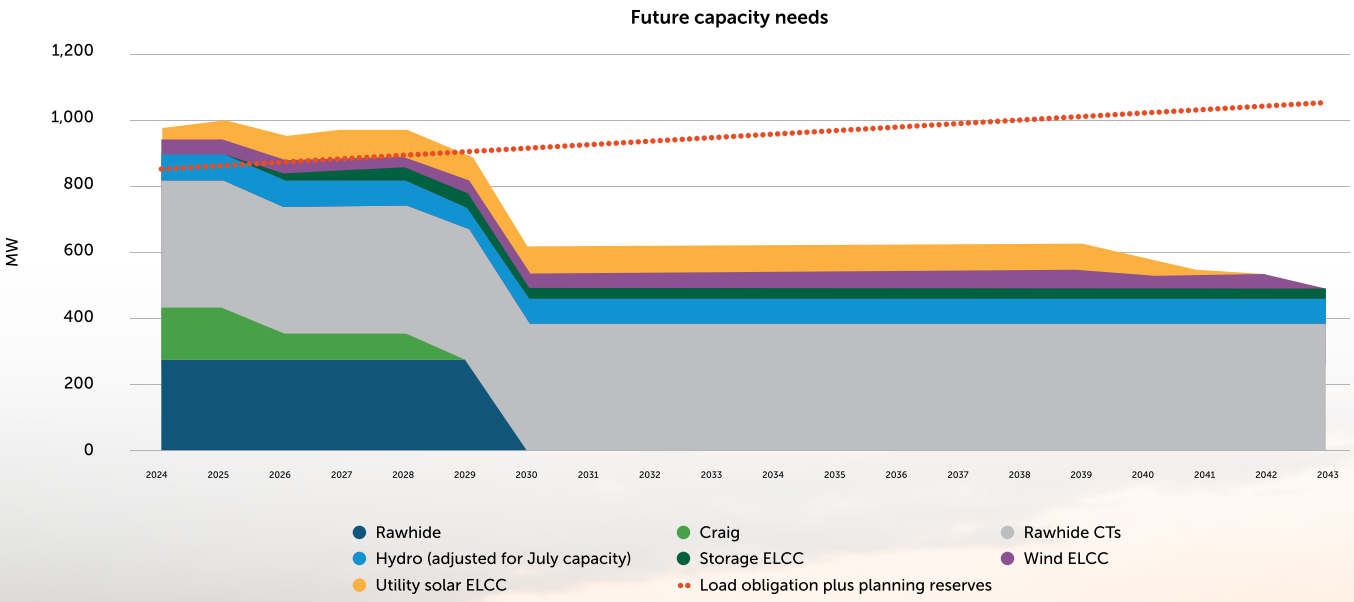



**Figure 52.** *Future capacity needs*



The dotted red line shows capacity requirements, while the area chart shows the capacity available. By 2029, following the retirements of Craig coal units, Platte River would need to build some new capacity, and by 2030, with the retirement of Rawhide coal plant, the additional capacity requirement rises to about 200 MW. The gap continues to expand as our load continues to increase and when our existing wind and solar PPAs reach their maturation dates. The IRP process offers recommendations to fill this gap with the lowest cost, least-emitting reliable resources.

Figure 53 shows similar chart depicting the energy deficit that will need to be filled in this IRP. Note small changes in renewable energy from year to year are due to projected changes in excess or "dumped" renewable generation.

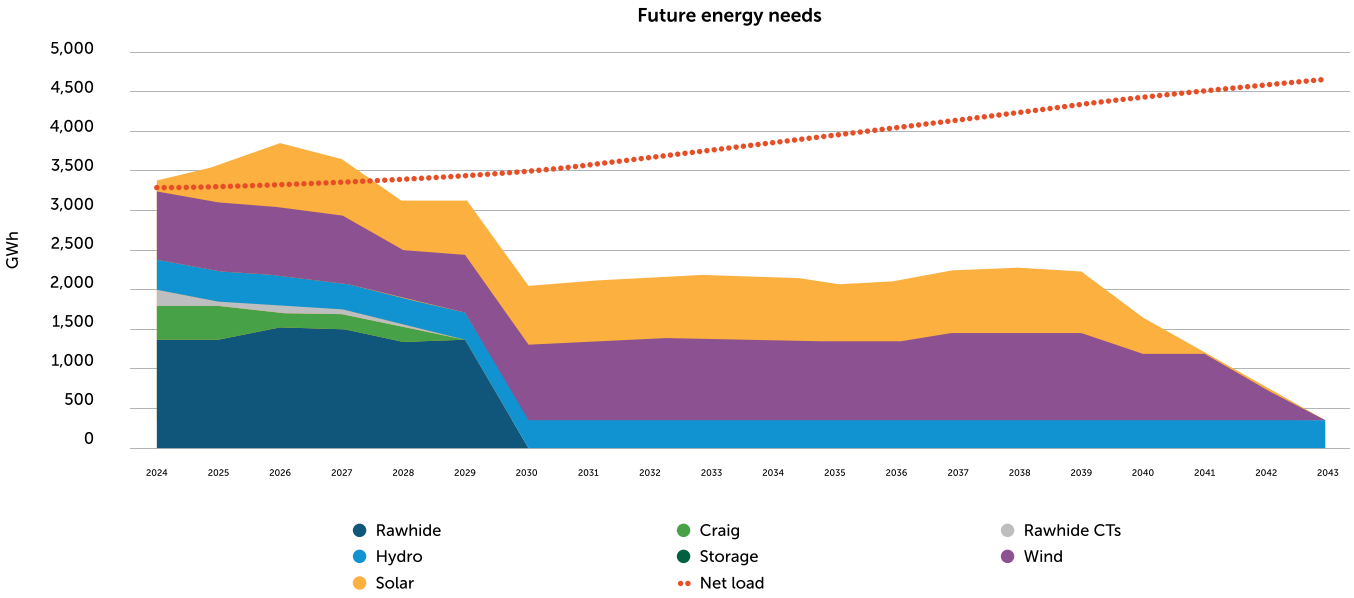



**Figure 53.** *Future energy needs*

Although capacity and energy gaps appear in 2030, Platte River plans to bring new resources online before 2030. This would give us time to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

# 7.4 Future portfolios

The portfolios selected for this IRP are designed to capture the range of potential paths available to Platte River as it transforms its generation portfolio and strives to meet the RDP goal. Reliability is the only firm constraint common to all portfolios. Other financial, operational and environmental metrics are optimized within the unique constraints of each portfolio.

Due to PRM requirements and to support reliability during dark calm events, Platte River keeps its existing combustion turbines in all portfolios. All portfolios emit some CO2 in 2030 because dispatchable noncarbon options will not be available by 2030, so thermal units are dispatched to balance the system during shortages. Portfolios that build new dispatchable thermal generation assume a blend 50% green hydrogen fuel by 2035 to reduce CO2 emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO2 emissions. No new dispatchable thermal generation is allowed after 2030 and the IRP assumes long-duration energy storage becomes available in 2035. All portfolios assumed that future electricity prices would also include carbon taxes. Below is a brief description of all the portfolios.

## 7.4.1 No new carbon

In this portfolio, Platte River cannot add new thermal generation. Wind, solar and four-hour storage are the only new resource additions available until 2035, when long-duration energy storage is assumed to also become available. This portfolio is designed to test the feasibility of relying on the existing combustion turbines to maintain reliability, without adding new thermal generation.

## 7.4.2 Minimal new carbon

This portfolio is built to add minimal amount of new thermal generation. It adds only 80 MW of new dispatchable thermal generation.

## 7.4.3 Carbon-imposed cost

This portfolio is built with the cost of carbon assigned to the dispatch cost of all thermal units. This additional cost, assigning a dollar value to the externalities associated with emitting CO2, disincentivizes the construction and use of carbon-emitting resources unless it is more cost effective than other options after accounting for the social cost of carbon. Specifically, this is a least-cost portfolio where the assumed cost carbon emissions have been internalized into the optimization process.

### 7.4.4 Optimal new carbon

This portfolio is a balance between the additional new carbon and carbon-imposed cost portfolios in terms of reliability and cost, building 200 MW of new thermal generation. This portfolio is optimal to support reliability in all conditions, as dark calm and extreme weather events continue to become more severe, as they have in the recent past.

### 7.4.5 Additional new carbon

This portfolio is the result of a least-cost optimization. The model builds the lowest-cost portfolio that meets reliability standards, but adds no additional constraints to guide resource selection or operation.

## 7.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 54 illustrates the initial steps and the subsequent iteration through the remaining steps.

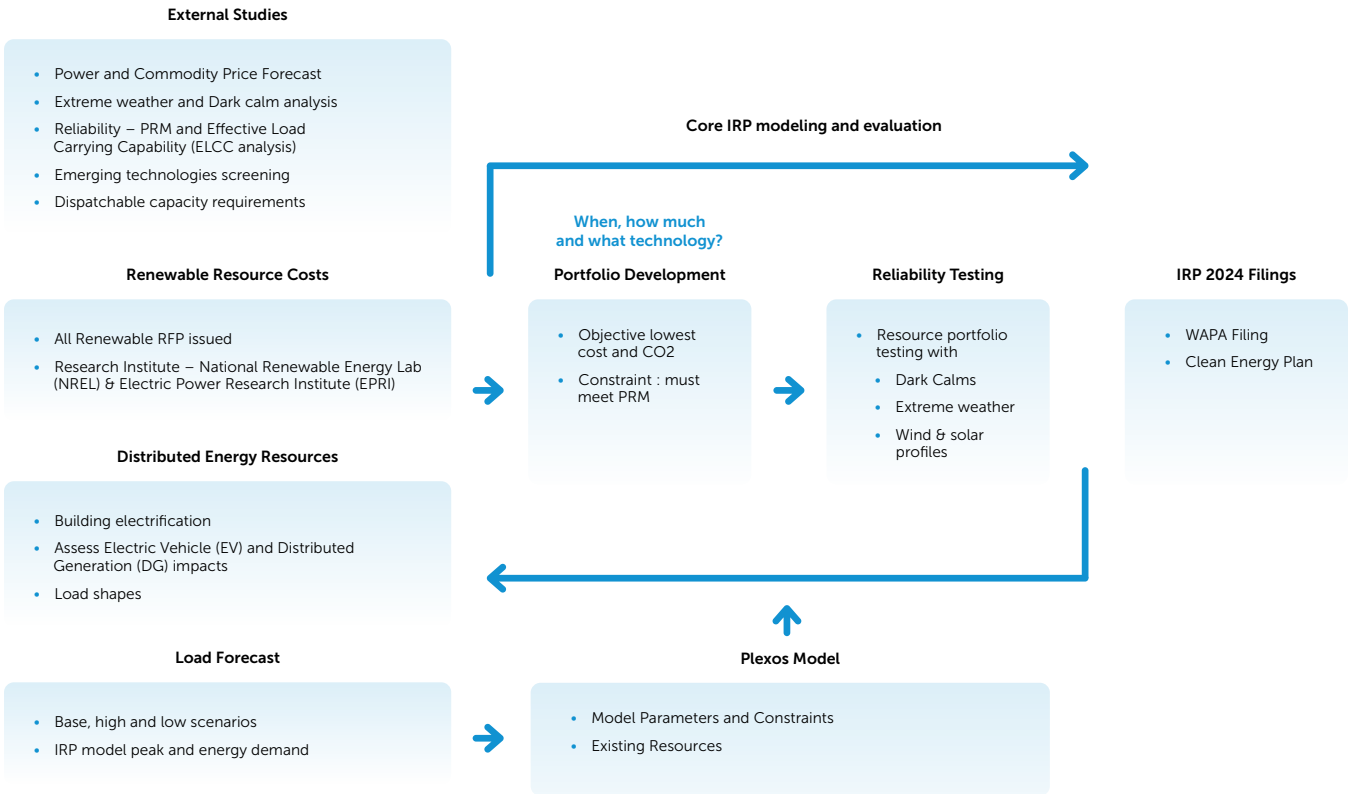



**Figure 54.** *IRP process*



## 7.5.1 Multi-step portfolio selection methodology

**Data collection and review:** Gather data on existing resources, including their performance and their expected operational lives; develop power and fuel price forecasts; review existing and potential future environmental regulations. These results provide a first step in understanding the planning landscape for the IRP.

**Demand forecasting:** Estimate future electricity demand, considering factors such as population growth, economic trends and technological advancements to project the energy needs over the planning horizon.

**DER forecasting:** Forecast new sources of demand, such as beneficial electrification and electric vehicles as well as additional demand-side resources, including customer-sited storage, rooftop solar, demand response and other programs.

**Technology assessment:** Evaluate the performance, costs, and environmental impacts of various energy technologies, including renewable energy sources, dispatchable thermal resources and energy storage. Based on the results of this high-level evaluation, Platte River can eliminate some technologies from consideration.

**Stakeholder engagement:** Collect feedback from a broad range of stakeholders. Community members, local businesses and advocacy



organizations are invited to offer their ideas and raise any concerns they have with the IRP process. This collaborative approach helps portfolios reflect the range of interests and priorities in the communities we serve.

## 7.5.2 Portfolio iterations

**Optimization modeling:** Use Plexos to develop and evaluate different portfolios of energy resources. Each portfolio is the result of a unique mix of inputs and constraints designed to test different aspects of the planning criteria, such as financial sustainability or environmental responsibility.

**Reliability testing:** Conduct reliability testing to identify uncertainties and potential challenges associated with different resource options. With high penetration of variable generation, the most critical risk tests quantify the system's exposure to dark calms or extreme weather. Platte River also reviews potential challenges associated with excessive energy length (too much energy produced compared to load) in a region expected to add substantial amounts of renewable energy in the future.

**Sensitivity analysis:** Explore how different external factors, such as fuel and market prices or emissions, might influence the performance of the portfolios. This helps develop plans that should be resilient under a range of future outcomes.

## 7.6 Reliability testing of portfolios

Because reliability is a foundational pillar, we first make sure each candidate portfolio is sufficiently reliable. As a starting point, a least-cost portfolio is developed to fill the capacity and energy gaps identified above while meeting the PRM requirement for every year of the planning horizon. Meeting the annual PRM requirement while applying the ELCC to energy-limited resources is useful, but does not test or guarantee reliability during extreme weather events or dark calms. So we conducted additional reliability testing through the Monte Carlo functionality in Plexos to understand how the portfolios might behave under stress conditions. Using the data from the extreme weather report supplied by ACES and historical weather data from Vaisala, we modeled different system conditions with the following variables:

1. **Weather:** Wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years), drawn with equal probability across the suite of simulations. In our runs, with 504 iterations, each weather year was experienced 21 times.

2. **Thermal unit outages:** The software randomly draws the timing of thermal unit outages. The duration of outages is also hypothetical, but the software does align the random outages with the known long-term forced outage rate over the course of many draws.

3. **Load forecast error:** Each iteration simulated a potential deviation from the near-term load forecast. This represents a shift in load drivers, such as population changes or economic indicators, over the one-to-four-year horizon, which is too short for the utility to respond to. The system, as built, would need to cover these near-term divergences before new resources could be brought online in response. For this IRP, Table 24 summarizes the potential load forecast error outcomes.

| LFE | Probability |
|---|---|
| -4% | 7.26% |
| -2% | 24.10% |
| 0% | 37.28% |
| 2% | 24.10% |
| 4% | 7.26% |

**Table 24.** *Potential load forecast error outcomes*

4. **Dark calm events:** Based on observed historical events, the model simulated weather events with impacts on both load and weather-dependent generation. These events could last between one and five days, with a two-day event being the most common. Often, dark calm events occur with extreme weather events. In any year, the system would expect to experience a total of 248 hours of extreme weather conditions distributed across several events. As with thermal outages, specific years could experience higher or lower than average dark calm outages with the long-term average converging to the expected value over may iterations. Across all 504 iterations of our reliability modeling, the dark calm hours in a year varied from a low of 119 hours to a high of 458 hours. Specific details on the impact to wind, solar and load are described below.

    a. **Load:** Load is modeled to increase by 10% during the event, which is consistent with data seen in other regions during extreme weather events. This is primarily driven by increased heating load during winter storms while cooling load is expected to increase during heat dome events in the summer. This increase captures the load already embedded in the load forecast.

    b. **Building heating:** During extreme winter storms, some new load from heat pumps is expected to shift to much less efficient electrical resistance heating as temperatures drop below their operating ranges. This increase in load is captured individually and is quantified by the consultant who supplied the beneficial electrification forecast.

    c. **Solar:** During the winter months, solar generation during a dark calm averages 5% of its nameplate. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% because summer outages are often caused by extended overcast weather.

    d. **Wind:** During the winter months, wind generation during a dark calm averages 5% of its nameplate. This reduced production is primarily due to blade icing, but overspeed (wind too strong to safely operate turbines) also drives some outages. In the summer months, output during a dark calm event also averages 5%, as summer wind droughts, especially during heat dome events, are common.

## 7.7 Modeling tool

Platte River used the Plexos simulation and modeling tool for the 2024 IRP. Plexos is an economic dispatch and capacity expansion model developed by Energy Exemplar (www.energyexemplar.com).



# 08 IRP study results

This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO2 emission reductions and renewable energy penetration—metrics that align with Platte River's foundational pillars of financial sustainability and environmental responsibility. As noted previously, every portfolio considered in this IRP meets our reliability criteria (another foundational pillar).

## 8.1 Summary of five portfolios

Every portfolio assumed a common starting point of existing resources plus new, near-term resource additions from recently signed agreements and solicitations under development. These are considered "committed" resources and the IRP process considers them "given," just like existing resources. These near-term additions represent Platte River's best estimate of solicitation results. In the current environment, project timelines, pricing and size are uncertain and subject to change. Platte River remains flexible and will adjust future capacity acquisitions to compensate for changes to current acquisitions.



## 8.1.1 Load forecast with DER assumptions

Customer load and DER projections for all the portfolios are similar. Therefore, the various portfolios primarily represent different supply-side options. Load forecast and DER projections are discussed in detail in chapter 5. Figures 37 and 38 in Chapter 5 show annual peak and energy forecasts and DER impact through the planning period. Figures 55 and 56 illustrate annual peak and energy forecasts for quick reference.

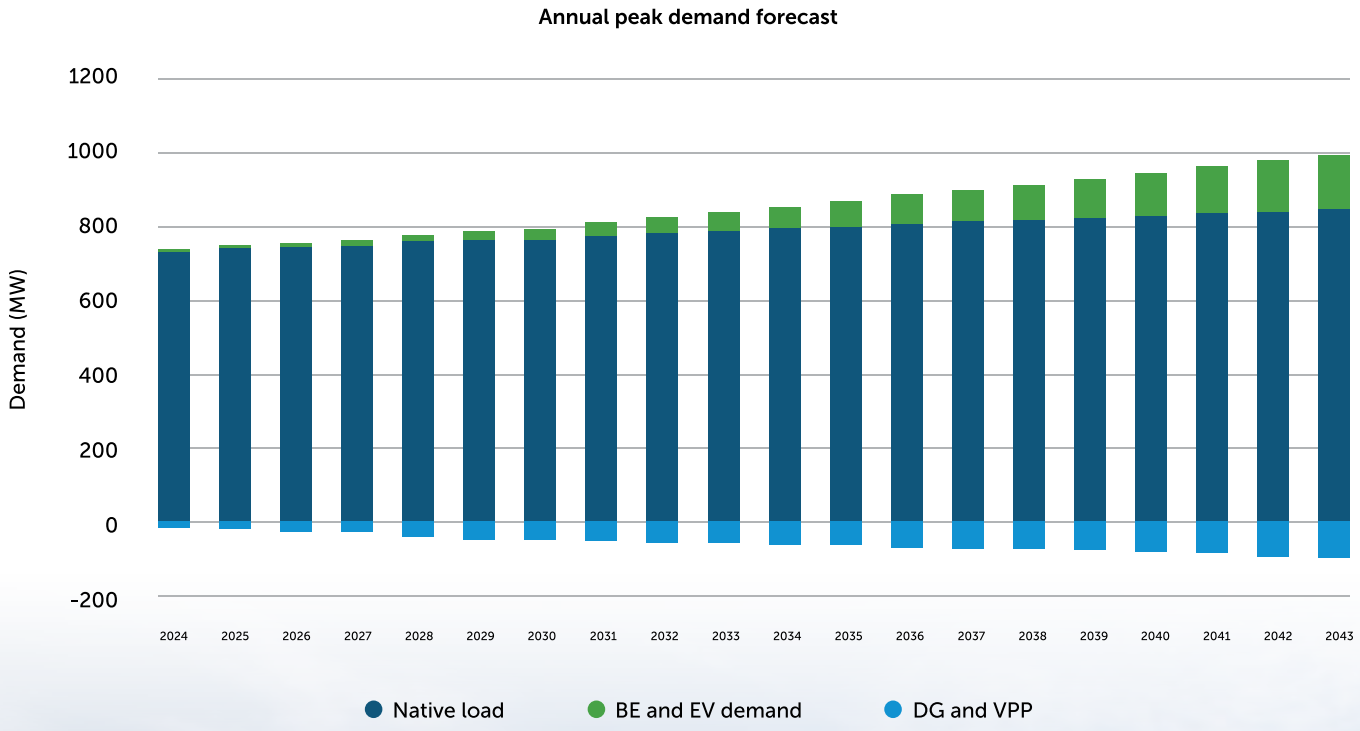



**Figure 55.** *Annual peak demand forecast*



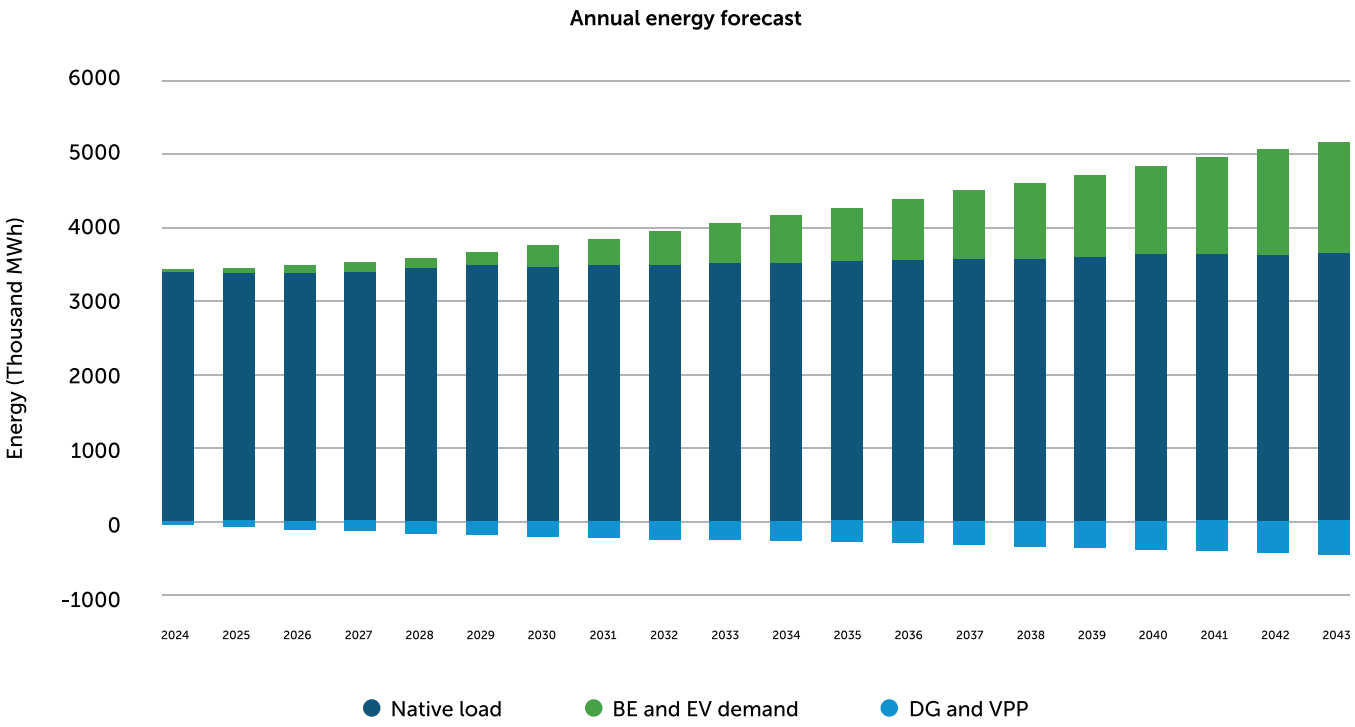



**Figure 56.** *Annual energy forecast*

Figures 55 and 56 illustrate that DERs are projected to grow much faster than the base load. Distributed generation, which is largely rooftop solar, reduces base peak load by 7% in 2030 and 10% by 2040. The growth of building beneficial electrification and EVs is even faster. Together, these add about 8% to the annual energy demand by 2030 and 34% by 2040.

Table 25 summarizes the utility-scale resources common to all portfolios before Platte River developed and optimized its expansion plans. As described in earlier sections, there are also DER resources embedded in every portfolio that are not subject to optimization during the modeling process.

| | Existing resources MWs | Near-term solicitation MWs | Total MWs |
|---|---|---|---|
| Wind | 231 | 250 | 481 |
| Solar | 52 | 300 | 352 |
| Battery energy storage systems | 1 | 50 | 51 |
| Long-duration storage | 0 | 10 | 10 |

**Table 25.** *Existing and committed resources*



Additionally, the following assumptions are common to all the portfolios:

- No new thermal generation is constructed after 2030 and all subsequent resource additions will be noncarbon-emitting resources.
- Long-duration energy storage technology is available from 2035 onwards.
- New thermal generation uses a fuel blend containing 50% green hydrogen from 2035 onwards.
- All thermal generation uses 100% green hydrogen fuel from 2040 onwards, eliminating CO2 emissions.

The portfolios developed in this IRP cover a broad range of potential pathways Platte River might consider as it decarbonizes its power supply portfolio. We are committed to completely retire coal generation by the end of 2029 so the expansion plans include aggressively adding renewable energy. Each portfolio adds 600-800 MW of new renewable energy capacity, although the mix between wind and solar may be different in each portfolio as the optimization seeks to minimize cost while meeting reliability metrics.

Platte River also models additional thermal units and storage to complement its renewable energy acquisitions and comply with reliability criteria. The main differences between the portfolios are the choices about adding thermal resources and storage.

Table 26 summarizes the resources added during the resource acquisition period, as well as the final buildout at the end of the planning horizon in 2043. Note the solar and wind energy additions closely converge by 2043, with only a 100 MW capacity spread between the highest and lowest additions. This is because all portfolios depend heavily on renewable energy, with thermal energy largely acting as a reliability backstop.

| | No new carbon | Minimal new carbon | Carbon-imposed cost | Optimal new carbon | Additional new carbon (lowest cost) |
|---|---|---|---|---|---|
| **2024-2029 incremental additions (MWs)** | | | | | |
| Wind | 300 | 300 | 400 | 400 | 300 |
| Solar | 450 | 500 | 350 | 300 | 300 |
| Four-hour storage | 2,850 | 1,050 | 275 | 175 | 100 |
| Long-duration storage | 10 | 10 | 10 | 10 | 10 |
| Dispatchable thermal | 0 | 80 | 160 | 200 | 240 |
| **Final 2043 Portfolio (MWs)** | | | | | |
| Wind | 885 | 885 | 985 | 885 | 985 |
| Solar | 600 | 600 | 550 | 600 | 450 |
| Four-hour storage | 2,850 | 1,100 | 400 | 275 | 175 |
| Long-duration storage | 10 | 160 | 10 | 160 | 110 |
| Dispatchable thermal | 0 | 80 | 160 | 200 | 280 |

**Table 26.** *Summary of five portfolios*

Additional detailed tables are provided in the following section for each portfolio, showing annual capacity additions by each category, further divided into new and existing resources.

## 8.2 Individual portfolio details

In this section we describe notable features of each portfolio and show the 20-year projections for each by year and by resource type.

### 8.2.1 No new carbon portfolio

This portfolio does not add any new thermal generation but continues to operate the existing natural gas CTs at Rawhide. To serve its future energy and reliability needs, Platte River adds an incremental 300 MW of wind and 450 MW of solar. To maintain reliability, the portfolio relies on four-hour battery storage with a total addition of 2,850 MW by 2029.

The substantial buildout of four-hour storage in the early years eliminates the need for additional storage during the planning period. Table 27 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 450 | 450 | 450 | 450 | 500 | 500 | 500 | 500 | 500 | 550 | 600 | 700 | 550 | 450 | 550 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 400 | 560 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 1452 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2850 | 2850 | 2850 | 2850 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **3457** | **4806** | **4607** | **4628** | **4698** | **4716** | **4827** | **4843** | **4861** | **4929** | **4997** | **5117** | **5088** | **5090** | **5186** | **5263** |

**Table 27.** *No new carbon portfolio annual resource additions (in MW)*

### 8.2.2 Minimal new carbon portfolio

This portfolio allows only 80 MW of new thermal generation. Due to this constraint, this portfolio requires a substantial amount of four-hour storage by 2030, as much as 1,050 MW. This portfolio also adds 300 MW of wind and 500 MW of solar by 2030. This is the most additional solar among all the portfolios, complementing the four-hour storage needed to cover daily peaks. After 2030, more wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 28 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 450 | 500 | 500 | 500 | 500 | 500 | 550 | 550 | 600 | 700 | 700 | 750 | 600 | 500 | 600 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 560 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 552 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1050 | 1050 | 1075 | 1100 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 110 | 110 | 110 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2637** | **3136** | **2937** | **2958** | **2978** | **2996** | **3057** | **3173** | **3241** | **3359** | **3427** | **3497** | **3468** | **3520** | **3641** | **3693** |

**Table 28.** *Minimal new carbon portfolio annual resource additions (in MW)*

### 8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO2 for society. Due to the increased cost for CO2 emissions, this portfolio limits the addition of new dispatchable thermal units to 160 MW and favors four-hour battery storage, with 275 MW of new capacity. As with other plans, wind and solar are the primary energy sources, with 400 MW of new wind and 350 MW of new solar by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 29 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 350 | 350 | 350 | 400 | 450 | 450 | 450 | 450 | 450 | 450 | 500 | 450 | 450 | 500 | 550 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 400 | 400 | 460 | 400 | 400 | 400 | 400 | 500 | 500 | 500 | 600 | 600 | 660 | 760 | 760 | 985 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 127 | 277 | 277 | 302 | 327 | 352 | 377 | 377 | 377 | 377 | 377 | 377 | 375 | 375 | 375 | 400 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 160 | 160 | 160 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2242** | **2391** | **2192** | **2238** | **2333** | **2426** | **2462** | **2628** | **2646** | **2664** | **2782** | **2852** | **2873** | **3025** | **3071** | **3173** |

**Table 29.** *Carbon-imposed cost portfolio annual resource additions (in MW)*

### 8.2.4 Optimal new carbon portfolio

This portfolio adds 200 MW of new dispatchable thermal resources and 175 MW of new battery storage as it balances capacity support across both thermal and batteries. Like the carbon-imposed cost portfolio, this portfolio adds 400 MW of wind but slightly less solar, with 300 MW of new capacity by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 30 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 450 | 450 | 450 | 550 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 400 | 400 | 460 | 400 | 400 | 400 | 400 | 500 | 500 | 500 | 600 | 600 | 660 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 102 | 177 | 177 | 202 | 227 | 252 | 252 | 252 | 252 | 252 | 252 | 252 | 250 | 250 | 250 | 275 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 160 | 160 | 160 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2257** | **2281** | **2082** | **2128** | **2173** | **2216** | **2327** | **2493** | **2511** | **2529** | **2647** | **2717** | **2788** | **2840** | **2936** | **3038** |

**Table 30.** *Optimal new carbon portfolio annual resource additions (in MW)*

### 8.2.5 Additional new carbon portfolio

The primary objective of this portfolio is to minimize costs. To do so, this portfolio relies on 240 MW of new dispatchable thermal resources to provide firm capacity. Renewables still supply most of the energy, with 300 MW of new wind and 300 MW of new solar by 2030. To help manage the renewable energy, this portfolio adds 100 MW of storage. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 31 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 280 | 280 | 280 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 350 | 350 | 350 | 350 | 400 | 400 | 350 | 400 | 450 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 500 | 500 | 500 | 600 | 600 | 600 | 660 | 760 | 760 | 985 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 52 | 102 | 102 | 102 | 127 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 150 | 150 | 150 | 175 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 110 | 110 | 110 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2147** | **2146** | **1947** | **1968** | **2013** | **2056** | **2267** | **2383** | **2401** | **2519** | **2537** | **2607** | **2678** | **2770** | **2816** | **2918** |

**Table 31.** *Additional new carbon portfolio annual resource additions (in MW)*

# 8.3 Comparative analysis of portfolios

## 8.3.1 Portfolio costs

As part of "least-cost" resource planning and optimization, the Plexos model captured relevant incremental costs associated with building, acquiring and operating the power supply portfolios over the 20-year planning horizon. Platte River excluded other costs from the model, like depreciation of existing transmission and generation infrastructure, cost of DERs and administrative and general costs. While these additional costs are important, they are not relevant to the capacity expansion planning process. The cost comparison presented here is not a rate forecast because it does not capture the full revenue requirement needed to set rates. Figure 57 compares the annual cost of all five portfolios.

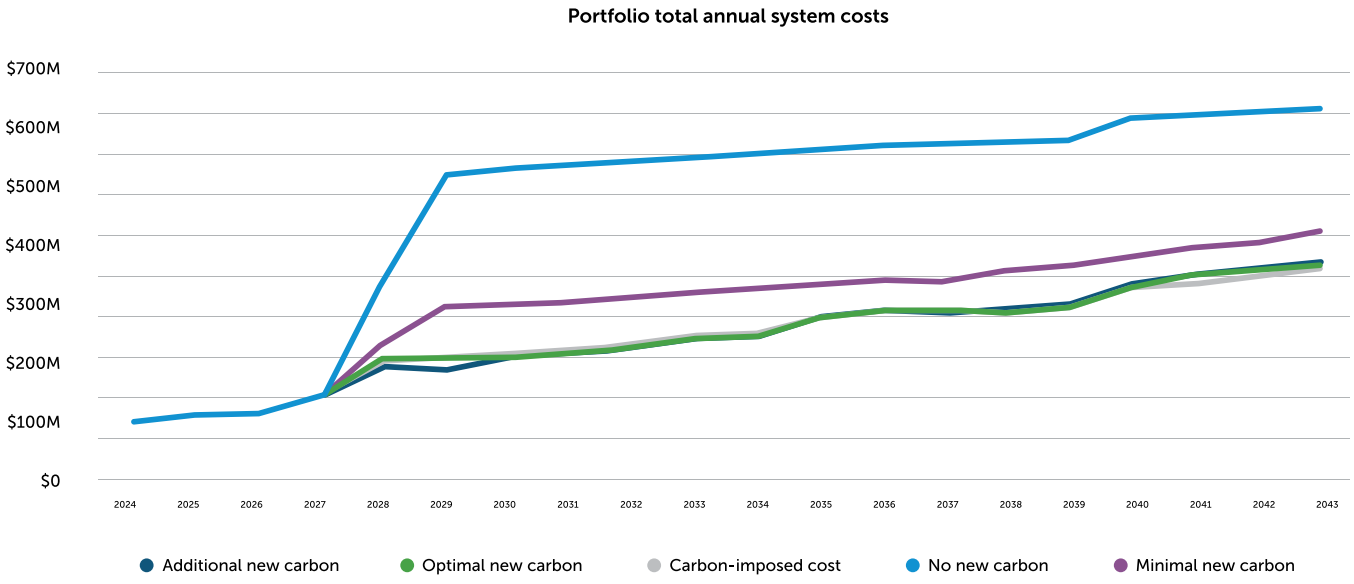



**Figure 57.** *Portfolio total annual system costs*

The no new carbon portfolio stands out as significantly more expensive, with the large buildout of four-hour storage starting in 2027. Annual costs exceed $500 million per year by 2028 and continue an upward trend. The minimal new carbon portfolio is also noticeably more expensive than others, again due to the large battery buildout, with annual costs exceeding $300 million by 2029. The remaining portfolios' costs are similar, with some annual deviations due to small changes in resource size and timing. Looking at the present value of the total portfolio cost in Table 32, costs for the carbon-imposed cost, optimal new carbon and additional new carbon portfolios are within 1%

of each other. But the minimal new carbon portfolio is about 20% more expensive than the three lower-cost portfolios (on a net present value basis), while the no new carbon portfolio is almost twice as expensive, costing an extra $2.6 billion over the planning horizon.

| 20-year net present value ($000) | |
|---|---|
| No new carbon | $5,344,991 |
| Minimal new carbon | $3,372,202 |
| Carbon-imposed cost | $2,779,024 |
| Optimal new carbon | $2,772,407 |
| Additional new carbon | $2,761,036 |

**Table 32.** *Portfolio net present value cost comparison*

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 33 highlight the complementary roles of renewable energy and thermal units in the optimal new carbon portfolio. In this case, when looking at the net present value of costs from 2030 through 2043, thermal units account for about 29% of the total cost while supplying almost 58% of the firm capacity and only about 7% of the energy. In contrast, noncarbon resources account for nearly 49% of the cost while contributing just over 91% of the energy but only about 23% of the firm capacity. The thermal resources are more cost-efficient at contributing capacity while noncarbon resources are more cost-efficient at contributing energy. A reliable and low-cost portfolio needs an optimal combination of both capacity and energy. While battery storage does not generate energy, it shifts the renewable production to omitted renewable production hours, thereby contributing to capacity needs and supporting renewable energy integration.



| | % of cost | % of generation | % of capacity |
|---|---|---|---|
| Thermal | 29.2% | 6.9% | 57.9% |
| Noncarbon | 48.8% | 91.5% | 23.1% |
| Battery storage | 15.1% | 0.0% | 19.0% |
| Purchases | 6.9% | 1.6% | 0.0% |
| **Total** | **100.0%** | **100.0%** | **100.0%** |

**Table 33.** *Optimal new carbon portfolio: cost, energy and capacity contribution breakout*

## 8.3.2 Portfolio CO2 emissions

Lowering CO2 emissions is a primary metric driving portfolio development and selection. While there are many ways to quantify a portfolio's emissions, this IRP uses the methodology developed in conjunction with Colorado's Clean Energy Plan (CEP)[29] rules.

Under this methodology, stack emissions from the portfolio are adjusted to reflect additional emissions associated with energy purchases while energy sales assign the associated CO2 to the counterparty buying energy. This netting prevents companies from avoiding emissions by outsourcing generation to an outside counterparty and helps Colorado measure total CO2 emissions due to electricity production and consumption within the state. This methodology also avoids penalizing companies for supplying energy to other utilities. This methodology is a good match for a future market where energy is entirely sold into and purchased from the market without regard to how individual companies balance load and generation. Figure 58 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

[29] In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

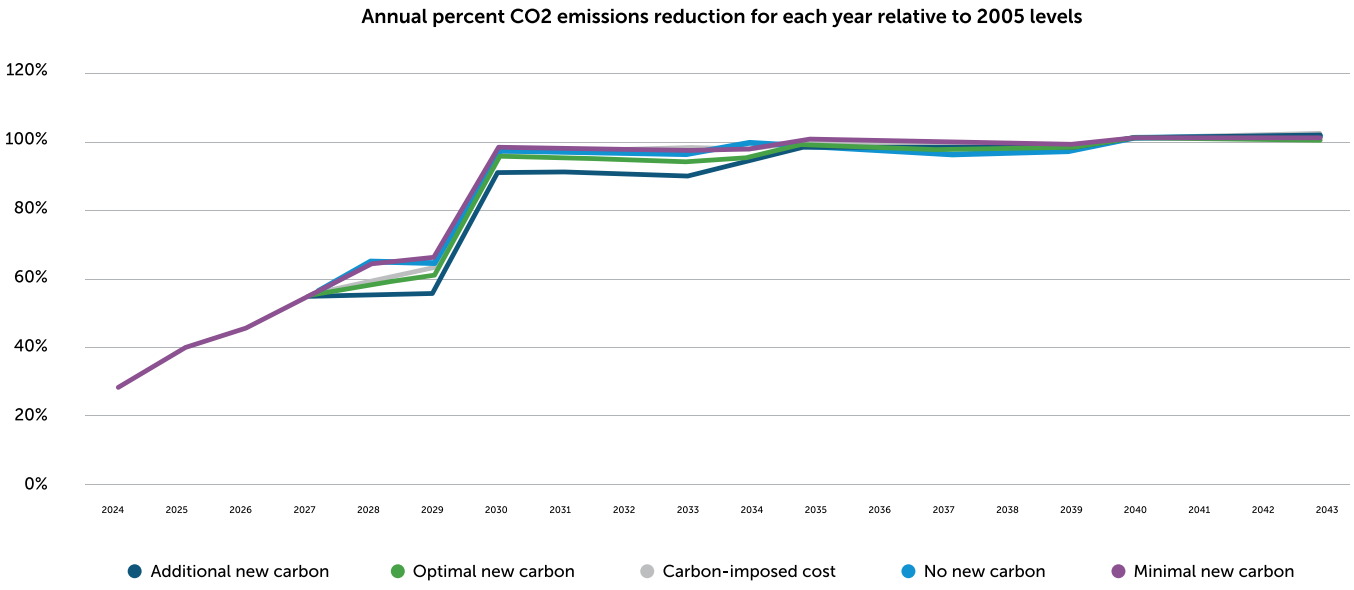



**Figure 58.** *Annual percent CO2 emissions reduction for each year relative to 2005 levels*

Starting in 2025, Platte River makes substantial progress to reduce CO2 emissions due to the renewable energy additions and phased coal retirements. By 2027, we expect all five portfolios to achieve a 55% CO2 reduction. By 2030, the additional new carbon portfolio achieves a 91% reduction, while the remaining portfolios have reductions greater than 95%. After 2035, when the remaining thermal units should begin partially burning green hydrogen, the average carbon reduction for all five portfolios is 99%. This rises to 100% when we assume that all thermal units will transition to 100% hydrogen fuels in 2040, eliminating CO2 emissions.

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO2 reduction (from 2005 levels) by 2027 and one plan that reduces carbon further than its filed CEP; and

- Platte River's voluntary CEP showing its plan to achieve at least 80% CO2 reduction (from 2005 levels) by 2030.

In addition to CO2 emissions reductions, emissions from other pollutants, including volatile organic compounds, carbon monoxide and nitrogen oxides, will also decrease with the coal plant retirements. We assume the new dispatchable generation will use the best available control technologies to maintain compliance with state laws and minimize environmental impact on water resources and air quality.

## 8.4 Recommendation

### 8.4.1 Optimal new carbon portfolio



Planning is a dynamic process, and the IRP is snapshot in time. The 2024 IRP presents a possible future based on the best information available in the summer of 2023. The five portfolios presented in this chapter cover a wide range of future paths. All five portfolios provide reliable electricity supplies during the planning horizon under our assumed set of conditions and variables. But our assumed conditions will probably change. In fact, they will almost certainly change in the long run because we are living amid rapid transition. While all five portfolios provide hypothetical options to meet load requirements and reduce carbon emissions, we must select one that:

- Presents a path towards meeting our RDP and state goals.
- Meets Platte River's three pillars of reliability, financial sustainability and environmental responsibility.
- Presents a path where the actions taken in early years will not unnecessarily limit future options or intensify risks.

The following section highlights the key merits of each portfolio and provides a recommendation.

The **no new carbon portfolio** does not add any new CO2 emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO2-emitting path, as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO2 emissions post-2030 as other portfolios. Due to heavy reliance on four-hour battery storage, this portfolio may be unreliable in a dark calm event that spans more days than we have modeled. This portfolio does not present a plausible future path.

The **minimal new carbon portfolio** builds 80 MW of new thermal generation and 1,050 MW of new storage batteries, almost 50% more than



the expected peak demand in 2030. This portfolio emits the least CO2 but is more than 20% more costly than the optimal new carbon portfolio. Just like the no new carbon portfolio, due to heavy reliance on four-hour storage batteries, this portfolio may be unreliable in a dark calm that spans multiple days. Because it does not meet Platte River's requirements for reliability or financial sustainability, this portfolio does not present a workable future path.

The **carbon-imposed cost portfolio** builds 160 MW of new thermal generation and presents a workable path. While this portfolio is reliable for the historically experienced weather uncertainties, it may not be reliable if weather events continue to become more extreme as they have in the recent past.

The **optimal new carbon portfolio** builds 200 MW of new efficient thermal generation and presents a viable path. This portfolio presents a balance between the additional new carbon and carbon-imposed cost portfolios in both cost and the amount of new thermal generation. This portfolio better supports reliability if weather events continue to become more extreme, as they have in the recent past. This is our recommended portfolio.

The **additional new carbon portfolio** builds 240 MW of new efficient and flexible thermal generation. It is the lowest-cost portfolio but emits more CO2 than some other portfolios that also meet reliability and financial sustainability pillars. This portfolio presents a workable future path.

The carbon-imposed cost, optimal new carbon and additional new carbon portfolios are potentially workable options. There are important differences among the three. After careful consideration, Platte River recommends the optimal new carbon portfolio because it optimally balances the organization's three foundational pillars, offers more flexible and lower-risk early decisions, has the robustness to withstand changes in assumptions and helps advance the 100% noncarbon energy goal of the RDP.

The recommended portfolio is a possible path for the future and not a firm plan. Platte River will further refine this path during implementation, incorporating market conditions, technology evolution, availability, and cost and timing of new resources. This plan will evolve as needed to align with our board's direction and our owner communities' wishes. Staff will continue to refine this portfolio with new data, assumptions, and market conditions. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining its three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

## 8.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, costs of renewables, DER adoption rates, market evolution, technology evolution, and other inputs. But these inputs are unlikely to occur exactly as assumed, requiring us to adapt. In this section, we outline the risks our plan faces, summarize our sensitivity analyses and provide options to adjust the plans for key risks. As time passes and newer information is available, we will modify our plans.

### 8.5.1 IRP risks and barriers

As Platte River moves forward with this IRP implementation, we must consider two types of risks. First, there are execution risks that complicate portfolio implementation. These risks tend to be very specific to the composition of the portfolio, driven by large, complex external factors (such as global supply chains) and are difficult to hedge because they are unique and difficult to forecast. We discuss these risks in detail below.

#### 8.5.1.1 Execution risks

- **Cost escalation** – As discussed in section 3.4.3, renewable costs continue to escalate dramatically. Platte River uses the latest market data to develop plans, but costs continue to rise, and new generation may be more expensive than anticipated. Renewable energy seems to carry the highest exposure due to both high market demand and complex, immature supply chains. Thermal generation has seen moderate escalation and other resource additions could be impacted by trade policies. Platte River must be prepared to adjust to the best portfolio mix to reflect evolving cost considerations.





- **Siting complications** – Individual projects have unique siting challenges. Platte River must address community concerns about the impact of a project itself or its transmission connections. Local regulation can also shift rapidly and require project modifications that often add costs. Projects may also encounter unexpected geological, hydrological or environmental conditions.

- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimates, but technology development is beyond Platte River's control. If specific storage technologies fail to mature or hydrogen is not available at the required volumes, the portfolio would need to be reoptimized to accommodate this new reality. More specifically, we assumed long-duration energy storage and green hydrogen will be available and economically viable for commercial deployment in 2035 to help continue to decarbonize Platte River's resource mix . If these technologies are not available at the projected dates or are available sooner, our decarbonization schedule will change accordingly.

- **DER adoption rates** – Platte River is proactively working with its owner communities to forecast and incentivize customer-sited resources. Like other technology forecasts, the exact trajectory of deployment of many new and emerging technologies is uncertain. Rooftop solar, electric vehicles, beneficial building electrification and battery storage systems



all impact both the energy mix and flexibility of the system. If there are unforeseen breakthroughs or complications, Platte River will need to adjust its resource mix in response.

## 8.5.1.2 Operational risks

There are operational risks that can occur in each plan once they are executed. It is easier to understand and quantify these operational risks with specific model runs. Their impact on portfolio viability is still significant and uncertain, but it is easier to evaluate the quantifiable tradeoffs.

- **Fuel and market price risk** – Portfolios are developed using the best estimates of future fuel and energy market prices. Past volatility suggests the potential for future volatility. Sensitivity runs modeling gas and power prices help establish each portfolio's susceptibility to this input and the consequences of future deviations from the expected value.

- **Regulatory risk on carbon accounting and emissions** – There continues to be a range of opinions on how carbon emissions will be regulated. The presence or absence of a carbon tax can impact the economics of a portfolio. Again, a sensitivity analysis can help quantify the financial impacts of a carbon tax.

- **Market evolution** – The implementation of a western energy market will impact different resources in different ways. Transmission congestion may erode the economics of remotely sited resources, while a robust energy market may impact price levels and volatility. If multiple utilities add renewable resources and transmission constraints emerge in moving power out of our region, there is a risk that excess renewable generation will depress market prices. This risk is more difficult to quantify than other operational risks, but Platte River continues to explore the potential range of impacts as the market develops.

The risks described above can impact a portfolio in different ways. One way to analyze their impacts is to conduct sensitivity analyses, where we change a driver or variable and measure the resulting impact on the portfolio. Section 8.5.2 discusses these analyses.

Because these risks and assumptions can change simultaneously, the combined effect can be large and drive us to change the portfolio mix. In section 8.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

## 8.5.2 Sensitivity analyses

To understand the robustness of the modeled portfolios, the IRP process tests the portfolios under assumptions different from the base assumptions. In a sensitivity analysis, a single assumption or input is changed (gas prices, for example) and the portfolio is re-evaluated. Portfolios with stronger responses to the new assumption or input show greater risk. This analysis provides a deeper understanding of the tradeoff between cost and risk. For this IRP, Platte River performed sensitivity analyses on two main inputs: natural gas prices and renewable energy prices.

### 8.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences regional market prices, which impacts the volume and cost or revenue of imports and exports to and from the Platte River system. Second, the portfolios continue to consume modest amounts of natural gas in the future, so changes in price directly impact the economics of the thermal generation. In this analysis, gas prices were tested at both higher and lower levels than the base assumption used in the portfolio development. Siemens, the supplier of the base gas price forecast, also supplied the high and low gas price trajectories, seen in Figure 39 earlier in this document, as well as associated market prices for each sensitivity.

### 8.5.2.2 High gas prices

Under this sensitivity, gas prices are 20% higher on average from 2030 to 2040. On a net present value basis, the portfolios' costs change very little, indicating the relatively small role of gas in future portfolios. On the low side, there is a 0.3% savings for the minimal new carbon portfolio while the additional new carbon portfolio has a cost increase of 1.4%. In general, higher gas prices increase the system operating cost due to higher fuel expenditures, but these increases are partially offset by higher sale revenues from higher market prices. Portfolios with more gas generation will see a net increase in cost, while portfolios with more must-sell renewable energy will benefit from the attractive market prices and see a slight savings.



### 8.5.2.3 Low gas prices

For this sensitivity, gas prices remain relatively flat starting in 2026. While the base case and high-price sensitivity show average escalation rates of 4.45% and 5.71% respectively through 2043, the low-price curve has a net gain of 0.2% by 2043, with a small decline during the 2030s. As expected, the results are the opposite of the high gas price sensitivity. Since this sensitivity sees a larger change to gas prices, with an average decrease of 54% relative to the base assumption, the change in net present value is more noticeable than in the high gas price sensitivity. The additional new carbon portfolio sees a cost savings of 5.1% and the optimal new carbon portfolio sees a savings of 3.6%. The minimal new carbon and no new carbon portfolios see modest savings of 0.6% and 0.8%, respectively.

### 8.5.2.4 Renewable energy prices

As discussed in section 3.4.3, renewable energy projects have seen significant cost increases in recent years.

In addition to the cost drivers of the projects themselves (including supply chain issues and competition for renewable resources), a second source of uncertainty around the cost of new renewable energy comes from Platte River's expected market participation. There is some possibility that the market will fail to launch as planned, or will launch with a different mix of participants, which would leave some projects exposed to higher transmission costs than might otherwise be expected in a market. Assuming the market does move forward as planned, there is still substantial uncertainty around the additional costs of transmission congestion, both under the existing portfolio and as regional portfolios evolve with more renewable energy concentrated at the optimal sites. Without a market, or with a market that is more congested than expected, the delivered cost of our renewable energy would rise.

For these reasons, Platte River ran a sensitivity analysis on renewable energy prices. We evaluated price increases for new wind and solar projects under each portfolio. Table 34 compares the base assumption to the higher price sensitivity for selected years. We did not test prices for energy storage and thermal generation because Platte River has not seen similar price volatility in those markets and their transmission congestion risk is much lower.



| Wind cost (including transmission costs) | | | Solar cost | |
|---|---|---|---|---|
| | Base | High sensitivity | Base | High sensitivity |
| 2030 | 32.85 $/MWh | 40.99 $/MWh | 30.01 $/MWh | 40.37 $/MWh |
| 2035 | 34.82 $/MWh | 43.75 $/MWh | 31.22 $/MWh | 41.99 $/MWh |
| 2040 | 36.87 $/MWh | 46.67 $/MWh | 32.43 $/MWh | 43.62 $/MWh |

**Table 34.** *Renewable PPA prices*

Because each portfolio adds a similar amount of renewable energy, the results across the portfolios are reasonably close. On a net present value basis, the smallest change is a $181 million increase for the additional new carbon portfolio, while the largest increase is $198 million for the carbon-imposed cost portfolio. The optimal new carbon portfolio has a cost increase of $190 million, which is about a 7% increase if renewable energy prices reach the level projected in the sensitivity.

The last two columns of Table 35 illustrate how the relative difference among portfolio costs changes from the base case to the sensitivity case. These intra portfolio cost comparisons are shown relative to the lowest cost portfolio referred to as the additional new carbon  portfolio (labeled as "ANC" in the table below). For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the additional new carbon portfolio, while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

| | Base and sensitivity comparison | | | Intra portfolio cost comparison | |
|---|---|---|---|---|---|
| Portfolio | Base case | Sensitivity: high RE | % change | Base case: % diff vs. ANC | Sensitivity: % diff vs. ANC |
| No new carbon | $5,344,991 | 5,531,559 | 3.5% | 93.6% | 88.0% |
| Minimal new carbon | $3,372,202 | 3,559,856 | 5.6% | 22.1% | 21.0% |
| Carbon-imposed cost | $2,779,024 | 2,976,911 | 7.1% | 0.7% | 1.2% |
| Optimal new carbon | $2,772,407 | 2,962,228 | 6.8% | 0.4% | 0.7% |
| Additional new carbon | $2,761,036 | 2,941,920 | 6.6% | 0.0% | 0.0% |

**Table 35.** *Renewable PPA prices*

### 8.5.2.5 Sensitivity analysis summary

While uncertainty about some model inputs is unavoidable, quantifying the impacts of those uncertainties can help manage the risks associated with them. Table 36 compares the net present value costs across the base case assumptions and the sensitivities described above.

| Net present values | Base | High gas and power | Low gas and power | High renewable energy prices |
|---|---|---|---|---|
| No new carbon | $5,344,991 | $5,343,332 | $5,304,721 | $5,531,559 |
| Minimal new carbon | $3,372,202 | $3,363,500 | $3,352,897 | $3,559,856 |
| Carbon-imposed cost | $2,779,024 | $2,783,634 | $2,724,507 | $2,976,911 |
| Optimal new carbon | $2,772,407 | $2,794,671 | $2,672,710 | $2,962,228 |
| Additional new carbon | $2,761,036 | $2,800,210 | $2,620,375 | $2,941,920 |

**Table 36.** *Net present value cost comparison with gas prices and renewable prices*

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 37 converts the net present value costs into rankings for the base case and each sensitivity, with the result that the no new carbon portfolio is last under every assumption tested and the minimal new carbon portfolio is fourth under every assumption tested.

| Net present value rankings | Base | High gas and power | Low gas and power | High renewable energy prices | Average |
|---|---|---|---|---|---|
| No new carbon | 5 | 5 | 5 | 5 | 5.0 |
| Minimal new carbon | 4 | 4 | 4 | 4 | 4.0 |
| Carbon-imposed cost | 3 | 1 | 3 | 3 | 2.5 |
| Optimal new carbon | 2 | 2 | 2 | 2 | 2.0 |
| Additional new carbon | 1 | 3 | 1 | 1 | 1.5 |

**Table 37.** *Portfolio ranking with sensitivity analysis*

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO2 emissions. The optimal new carbon portfolio proves to be robust, with a second-place ranking in every run. This portfolio is, on average, only 0.9% more expensive than the best portfolio in any given sensitivity (including the base case). While some portfolios may perform better in a specific set of circumstances, the optimal new carbon portfolio performs well across the range of outcomes and proves to be a cost-effective and robust solution.

### 8.5.3 Excess renewable and market participation risk

With a substantial increase in intermittent renewable resources, Platte River faces an increasing risk from the mismatch in timing between customer demand and when renewable generation is available. Some of the mismatch can be managed with energy storage, but it would be impractical to balance the entire renewable energy portfolio using current battery storage technology. When there is insufficient renewable energy, Platte River can purchase energy from the market, withdraw stored energy, or rely on thermal generation to fill the gap. When there is too much energy, Platte River will store the excess (after meeting its load) and must sell any additional renewable energy into the market or curtail the resource.

Starting in 2030, Platte River anticipates having about 10% to 35% surplus energy on an annual basis. Of that excess, about 75% is expected to be sold, while the remainder will be curtailed due to limited energy demand and constrained transmission systems.

Because renewable energy contracts are structured as take-or-pay, Platte River must pay the full price of the PPA whether we take delivery of the energy or not. In this context, Platte River will sell excess renewable energy into the market if the market price is greater than $0 but will incur a loss if the market price is below the PPA price. Therefore, the economic value of the surplus renewable energy depends on the cost of the PPA relative to the market price of the energy at the time of the excess energy.

Given that the entire region is adding wind and solar resources, we anticipate market prices to be lowest when we have surplus renewable energy. Figure 59 illustrates the average expected monthly power prices in 2031 and monthly excess renewable energy as a percentage of the total monthly energy required by Platte River customers.

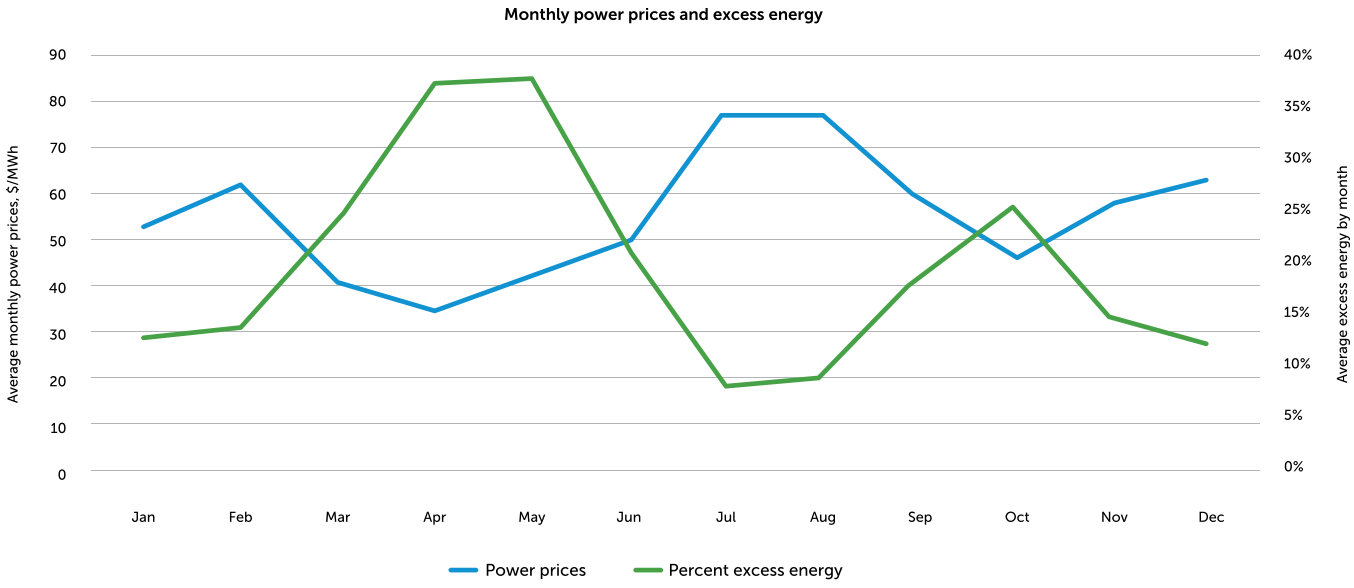



**Figure 59.** *Monthly power prices and excess energy*

The blue line shows average monthly prices, while the green line shows excess energy as a percent. The average prices are lowest in April and May, when the excess energy is above 35% of Platte River's needs. Excess energy is relatively low in higher-priced months of summer and winter.

To better understand the supply-demand balance and assess energy risk, Platte River staff analyzed expected hourly operations during the year 2031 using 24 historical hourly weather patterns for the recommended portfolio, which called for adding 400 MW of new wind by 2030. The diversity of weather data allows a broader quantification of the risk across multiple weather years, rather than relying on a single representative year.

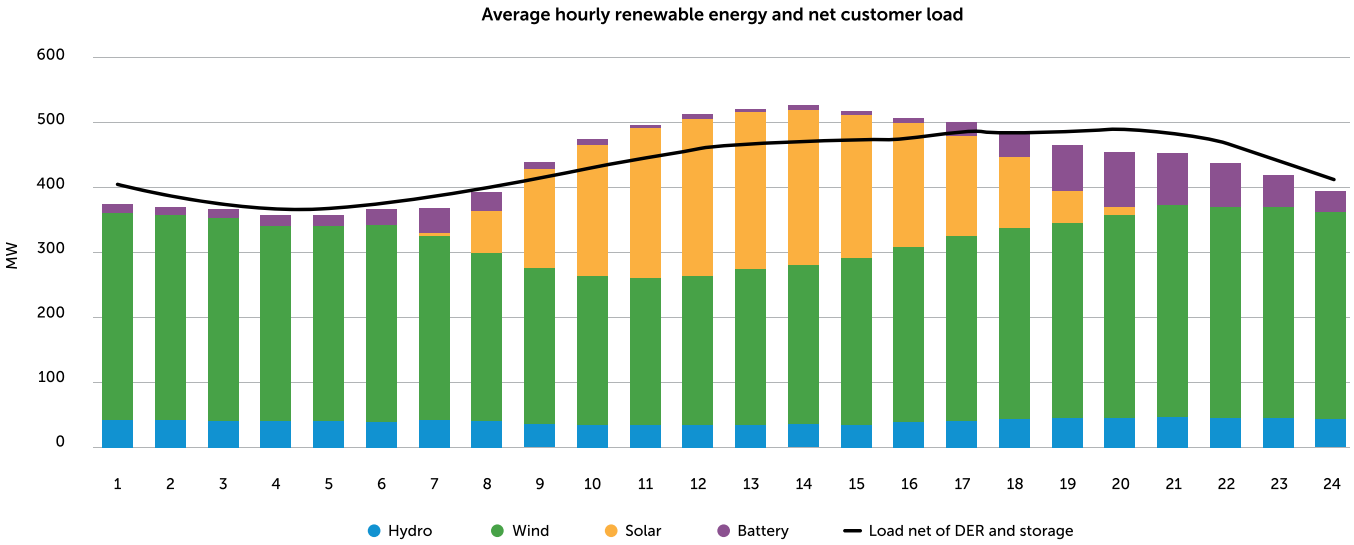



**Figure 60.** *Average hourly renewable energy and net customer load*

Figure 60 summarizes the average excess megawatts by hour of day and month of the year. During the day, we have excess energy in midday when solar output is high. However, during the morning and evening hours, when the load is ramping up, the Platte River system needs dispatchable capacity and market access.

Balancing this excess renewable energy with the need for sufficient energy during high demand is one of the primary tasks of this IRP. Platte River developed the recommended portfolio with 400 MW of new wind, with the wind power purchase price around $32/MWh, and market prices in the 2030s around $50/MWh, making excess energy revenue positive. However, if market prices continue to drop with the addition of renewable resources in the region and demand for renewable energy continuing to rise, the cost of renewable energy will increase. In this scenario, the risk is not only the limited value from excess renewable energy but also market price volatility.

Platte River will need to consider these risks before fully implementing the recommended plan. This exposure to factors outside Platte River's control makes managing the portfolio's risk a critical part of the execution phase. Platte River will continue to monitor commodity prices (like gas), market power price forecasts, and the cost of renewable energy to refine and rebalance the plan as necessary to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk if it is cost-effective.





# 09 Action plan

Platte River will continue to work toward the RDP goal over the next five years. Platte River plans to retire coal generation, add more renewable generation, add energy storage, add a VPP, join a full organized energy market and add efficient dispatchable thermal generation to complement renewable intermittency.
We expect to carry out the following specific activities.



# 9.1 2024-2028: Execution phase

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| Renewable energy acquisition | Contract for new 107 MW solar from the 2022 solar RFP | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| | Contract for new 250 MW wind from the 2023 wind RFP | 2024 | |
| | Begin commercial operation of 150 MW Black Hollow Solar project | 2025 | |
| | Begin commercial operation of a 130 MW solar project | 2027 | |
| Dispatchable capacity (reliability) | Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Issue RFP for four-hour battery energy storage system | 2024 | |
| | Review results from all-dispatchable-resource RFP | 2024 | |
| | Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include:<br>• Apply for air and land use permits<br>• Identify actions related to ordering some long lead time equipment, especially related to power transmission<br>• Develop initial project design and enlist engineering, procurement and construction contractor | 2024 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Dispatchable capacity (reliability)** | Issue RFP for systems and services to support development of a VPP that can provide dispatchable capacity for Platte River and the owner communities | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Issue RFP for dispatchable thermal resource development if the 2024 all dispatchable resource RFP does not result in an acceptable project | 2025 | |
| | With our owner's engineer and contractor, complete plant design for new resource and balance of plant services | 2025 | |
| | Complete battery energy storage system agreements | 2025 | |
| | Issue RFP for additional energy storage system | 2025 | |
| | Plan VPP systems design and architecture | 2025 | |
| | Start work on a demonstration project for long-duration energy storage system | 2025 | |
| | Build VPP systems, system integrations and develop key functionality | 2026 | |
| | Begin commercial operation of up to 25 MW of distributed energy storage from 2021 solar RFP | 2026 | |
| | Launch VPP with 7 MW dispatchable capacity | 2027 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Customer programs** | Plan and develop VPP customer programs | 2025 | Execution risks (section 7.5.1.1)<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Market evolution<br>VPP system integration<br>Third-party DER device aggregators |
| | Launch VPP customer programs | 2026 | |
| **Community engagement** | Continue public education campaign to engage communities, customers in the energy transition | 2024-2028 | |
| | Support renewable energy project acquisitions and engage communities through groundbreaking events, ribbon-cutting ceremonies | 2025-2028 | |
| **Transmission** | Complete construction and energize the 230-kV interconnection switching station (Severance substation) to interconnect new renewable resources | 2025 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| **Markets** | Begin training staff to prepare for SPP RTO West market entry | 2024 | Operational risks (section 7.5.1.2)<br>• Market evolution<br>System integration<br>Market tariff and resource adequacy |
| | Screen and select market interface software | 2024 | |
| | Begin testing operations in SPP RTO West | 2025 | |
| | Join SPP RTO West market operations on April 1 | 2026 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| Other enabling activities | Finalize and file a just transition plan with the state of Colorado for workers affected by Rawhide Unit 1's closure | 2024 | Interest rates |
| | Working alongside other owners, retire Craig Unit 1 (of which Platte River owns a 77 MW share) | 2025 | |
| | Initiate 2028 IRP process | 2026 | |
| | Issue bonds to fund capital investments | 2025-2026 | |
| | Continue 2028 IRP process including:<br>• Receive studies from external consultants<br>• Execute community engagement activities to educate public, collect stakeholder feedback<br>• Conduct modeling and analyze portfolios<br>• Compile draft report | 2027 | |

# 9.1 2024-2028: Execution phase

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Renewable energy acquisition** | Begin commercial operation of new wind generation | 2028 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| **Dispatchable capacity (reliability)** | Testing, commissioning, and operation of new dispatchable thermal resource | 2028 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Begin commercial operation of energy storage systems (for which RFP was issued in 2025) | 2028 | |
| | Grow VPP dispatchable capacity to 15 MW and develop market dispatch capabilities | 2029 | |
| | Grow VPP dispatchable capacity to 24 MW and develop distribution dispatch capabilities | 2029 | |
| | Develop a mobile app to help customers and distribution utilities connect with Platte River's system | 2028-2030 | |
| **Community engagement** | Support mobile app deployment with communications and community activations | 2028-2030 | |
| | Continue public education campaign to engage communities, customers in the energy transition | 2028-2030 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| Other enabling activities | Implement the Just Transition Plan | 2024-2030 | |
| | Working alongside other owners, retire Craig Unit 2 (of which Platte River owns a 74 MW share) | 2028 | |
| | Seek approval from Platte River Board for 2028 IRP; file with WAPA | 2028 | |
| | Retire Rawhide Unit 1 by December 31 | 2029 | |

# 10 Appendices





# **Appendix A:** IRP checklist for WAPA

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **IRP design, IRP study results**<br><br>**Power markets**<br><br>**Energy efficiency**<br><br>**DER integration, flexible DERs and the virtual power plant**<br><br>**IRP portfolios** | Does the IRP evaluate the full range of alternatives for new energy resources, including:<br><br>• new generating capacity?<br>• power purchases?<br>• energy conservation and efficiency?<br>• cogeneration and district heating/cooling applications?<br>• renewable energy resources? | ✓ | 6.3.3, 6.3.4, 6.3.5, 6.3.6, 6.3.7<br>7.1, 7.4, 8.2, 8.3<br>4.1.5, 6.3.4, 6.3.5, 5.3.2<br><br>5.3.1<br>7.4, 8.2, 8.3 |
| **Planning for a reliable future power supply** | Does the IRP provide adequate and reliable service to the customer's electric consumers? | ✓ | 7.3 |
| **IRP design, IRP study results** | Does the IRP take into account the necessary features for system operation? | ✓ | 4.2.1, 7.3, 8.5 |
| **DER integration, flexible DERs and the virtual power plant** | Does the IRP take into account the ability to verify energy savings achieved through energy efficiency? | ✓ | 5.3 |
| **DER integration, flexible DERs and the virtual power plant** | Does the IRP take into account the projected durability of such savings measured over time? | ✓ | 5.3 |
| **Load forecast methodology and data** | Does the IRP treat demand and supply resources on a consistent and integrated basis? | ✓ | 5.3, 5.4.1, 5.4.2 |
| **Planning for a reliable future power supply** | Does the IRP consider electrical energy resource needs? | ✓ | 7.3 |
| **Energy and capacity planning, DER integration, flexible DERs and the virtual power plant, supply side generation resources, IRP portfolios** | Does the IRP identify and compare resource options? | ✓ | 4.1.2, 5.3, 6.3, 7.4, 7.5 |

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **Comparative analysis of portfolios, portfolio recommendation, risk assessment and sensitivity analysis** | Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options? | ✓ | 8.3, 8.4, 8.5 |
| **Action plan** | Does the IRP include an action plan describing specific actions the customer will take to implement the IRP? | ✓ | 9 |
| **Action plan** | Does the IRP list the time period that the action plan covers? | ✓ | 9 |
| **Action plan** | Does the IRP include an action plan summary consisting of:<br>• Actions the customer expects to take in accomplishing the goals identified in the IRP?<br>• Milestones to evaluate accomplishment of those actions during implementation?<br>• Estimated energy and capacity benefits for each action planned? | ✓ | 9 |
| **Portfolio CO2 emissions** | Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts? | ✓ | 8.3.2 with additional text from environmental |
| **Portfolio CO2 emissions** | Does the IRP include a qualitative analysis of environmental effects in a summary format? | ✓ | 8.3.2 |
| **Stakeholder engagement process** | Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP? | ✓ | 3.7 |

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **Stakeholder engagement process** | Does the IRP include a brief description of public involvement activities? | ✓ | 3.7 |
| **Board resolution to approve the 2024 IRP** | Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met? | ✓ | Appendix C |
| **Board resolution to approve the 2024 IRP** | Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body? | ✓ | Appendix C |
| **Electricity demand** | Does the IRP contain a statement that the customer conducted load forecasting, including specific data? | ✓ | 5.1-5.4 |
| **Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios** | Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met? | ✓ | 7.3.2.2, 8.3.2, 5.3 |
| **Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios** | Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation? | ✓ | 7.3.2.2, 8.3, 5.3 |
| | Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA? | N/A | |

# **Appendix B:** 2024 Just Transition Plan

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

# 2024 JUST TRANSITION PLAN



# BACKGROUND

Platte River Power Authority (Platte River) is a not-for-profit, community-owned public power generation and transmission utility that provides safe, reliable, environmentally responsible and financially sustainable energy and services to the communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their distribution utility customers. Platte River owns and operates Rawhide Energy Station (Rawhide), located roughly ten miles north of Wellington, Colorado. Rawhide consists of one 280 megawatt (MW) capacity coal fired boiler (Unit 1) and five natural gas-fired combustion turbines with a combined 388 MW capacity (Units A, B, C, D and F) that support peak power demand. Additionally, Rawhide also has 52 MW of solar and a 2 MW-hour battery storage system.

Platte River, like other Colorado utilities, is transforming how it generates and delivers energy. In 2018, Platte River's board of directors (the board) approved the Resource Diversification Policy (RDP), which directed Platte River to proactively work toward achieving a 100% noncarbon energy mix by 2030 while maintaining Platte River's three foundational pillars of providing reliable, environmentally responsible and financially sustainable electricity and services. A significant milestone on the journey to 100% noncarbon energy is its commitment to retire Unit 1 by the end of 2029. This commitment is reflected in its current Integrated Resource Plan (2024 IRP) and in its Clean Energy Plan, which was submitted to the state of Colorado in 2022. This commitment is also included in Resolution 08-24 which formally announces Unit 1's accelerated retirement as part of the 2024 IRP. With Platte River's commitment to retiring Unit 1, the utility will submit this document – Platte River's Just Transition Plan – to the Colorado Office of Just Transition within 30 days of Platte River's board of directors approving Resolution 08-24 and the 2024 IRP.

Platte River is not just transforming its energy mix. Embracing the future will require Platte River to change and adapt as an organization. Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market in 2023 and will enter SPP's Regional Transmission Organization –West (RTO–West) in April 2026, which is one of the key advancements identified to further the RDP. To support entering RTO–West, Platte River is initiating a strategic workforce analysis to identify the necessary changes to its people, processes, and technologies.

Platte River's board passed Resolution 08-2020 (Workforce Resolution) in 2020, when Platte River announced Unit 1's retirement. The Workforce Resolution planned six principles that Platte River is committed to follow when implementing its transition plan. These principles are:

- Transparency
- Workforce Planning
- Workforce Opportunities
- Workforce Training
- Retention Strategies
- Transition Support

Platte River, through its Workforce Resolution and Just Transition Plan, will continue to demonstrate its unwavering commitment to support and retain employees who wish to remain with the organization through Unit 1's retirement and its transition to a clean energy future.

# PLATTE RIVER AT A GLANCE

Platte River Power Authority is a not-for-profit, community-owned public power utility that generates and delivers safe, reliable, environmentally responsible and financially sustainable energy and services to Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their utility customers.

### Headquarters

Fort Collins, Colorado

### General manager/CEO

Jason Frisbie

### Began operations

1973

### Staff

268

### 2023 peak demand of owner communities

680 MW

### 2023 deliveries of energy

4,506,208 MWh

### 2023 deliveries of energy to owner communities

3,161,533 MWh

### Transmission system

Platte River has equipment in 27 substations, 263 miles of wholly owned and operated high-voltage lines, and 522 miles of high-voltage lines jointly owned with other utilities.

# PLATTE RIVER POWER AUTHORITY'S 2024 JUST TRANSITION PLAN

As required by House Bill 19-1314 and to further its commitment to Unit 1's retirement and the 100% noncarbon goal of its RDP, Platte River submits this Just Transition Plan to the Colorado Office of Just Transition. Platte River views this Just Transition Plan as a living document and anticipates that it will revise both the Just Transition Plan and its IRP as Unit 1's Dec. 31, 2029 retirement date nears. Platte River's Just Transition Plan follows the six principles of its Workforce Resolution and supports its ongoing commitment to retain employees through the energy transition and to avoid involuntary separations (layoffs) due to Unit 1's retirement.






MARKET
09
22



# PRINCIPLE 1: TRANSPARENCY

Platte River management will make every effort to communicate impacts proactively and transparently to employees as decisions are made, including the timelines of planned events.

To implement this principle, Platte River consistently updates both Rawhide and Headquarters staff on the transition plan, including at plant and business meetings and through updates to Platte River's board. Platte River also discusses the upcoming transition, including its commitment to retain employees after Unit 1's retirement, with external candidates as part of the interview and hiring process. Platte River offers RTO–West training to the whole organization and will provide the results of its upcoming gap analysis to internal stakeholders so that each department can evaluate the changes to people, processes, and technology that will be needed in 2026 and beyond. Platte River also plans to provide this Just Transition Plan and the 2024 IRP to all employees through multiple channels and opportunities for employee to submit questions, concerns, and feedback on Platte River's transition.

Platte River's Just Transition Plan is led by a cross-functional team including representatives from power generation, operations, human resources, communications, and legal affairs and is sponsored by Platte River's Chief Operating Officer – Generation, Transmission and Markets. This cross-functional team currently plans additional outreach and communication to staff on workforce planning and workforce transition to accompany the Just Transition Plan and 2024 IRP. The cross-functional team is guided by the RDP, the Workforce Resolution and Platte River's Strategic Plan as it deploys Platte River's strategic workforce planning tools to further those goals and establish ongoing dialogue on how to best meet them in a just and transparent way.

# PRINCIPLE 2: WORKFORCE PLANNING

Platte River management will continue to evaluate and identify workforce needs and to communicate its needs to staff.

To implement this principle, Platte River's leadership, partnering with its human resources department, is currently using strategic planning, data modeling, and other workforce planning tools to anticipate Platte River's future workforce needs. While this modeling is an imperfect science, Platte River is committed to using the best tools and data available, and to continually updating its models as Unit 1's retirement nears and Platte River's future needs become clearer.

It is important to note that Platte River is growing as an organization, even as Unit 1 retires. It will need additional staff in many functional areas to meet the RDP and the Strategic Plan, including in power marketing, power delivery, compliance, information technology, and substation maintenance. Platte River has determined how future vacancies will provide opportunities to transition Rawhide employees to other positions in the organization.

Platte River's internal modeling also shows that its workforce transition will largely be driven by natural attrition and retirement, not through layoffs. Many current Platte River employees have more than 25 years of service. Historically, Platte River attrition has been low amongst its longest-tenured employees, a trend that it anticipates may change as more staff members reach retirement age. Platte River, like other employers, has experienced increased attrition and volatility amongst its newer employees, a trend that it anticipates will not change between now and 2029.

Figure 1 and Figure 2 show the general trends that Platte River has modeled and observed in attrition by years of service, both for the organization as a whole and for Rawhide.

**Figure 1: Platte River Attrition by Years of Service**

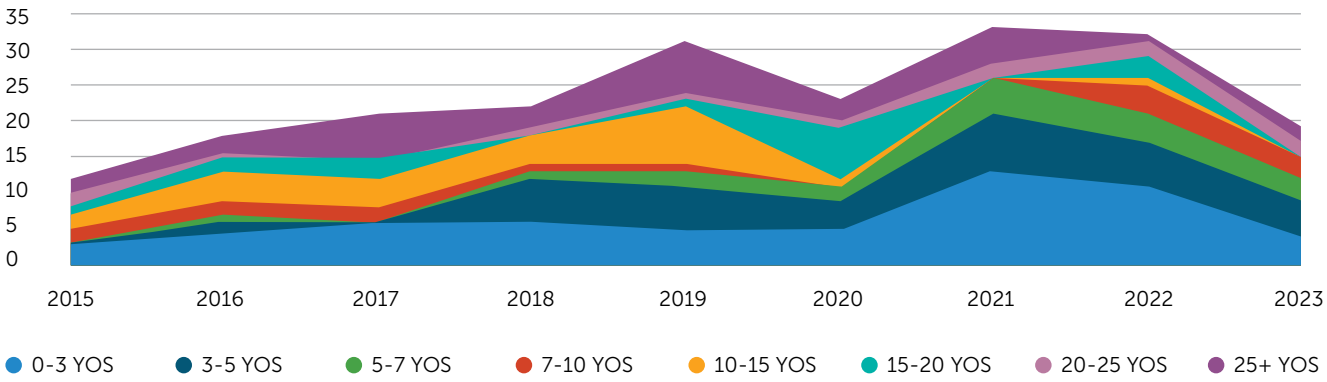


**Figure 2: Rawhide Attrition by Years of Service**

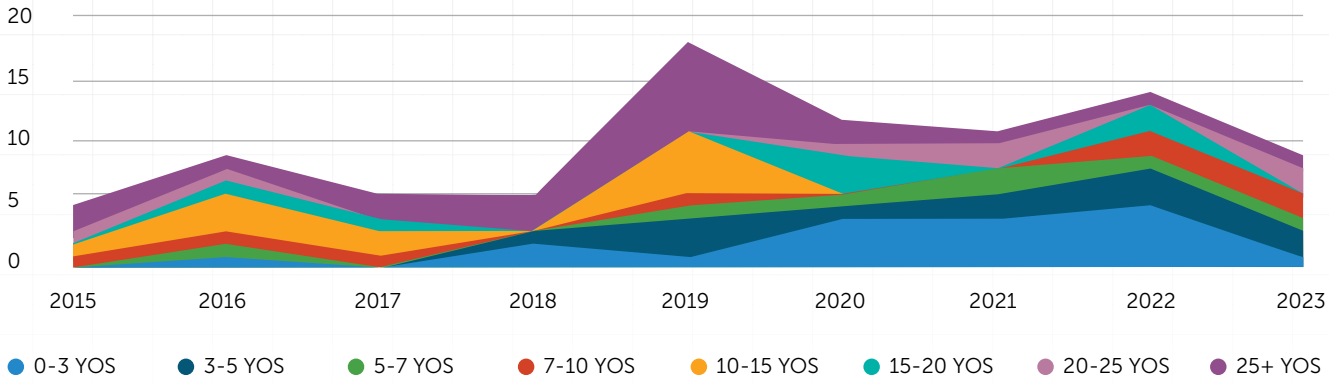



Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for natural attrition show that it will be understaffed at Rawhide in the latter part of the decade (for example, from 2027 to 2029).

**Figure 3: Platte River Attrition by Reason**

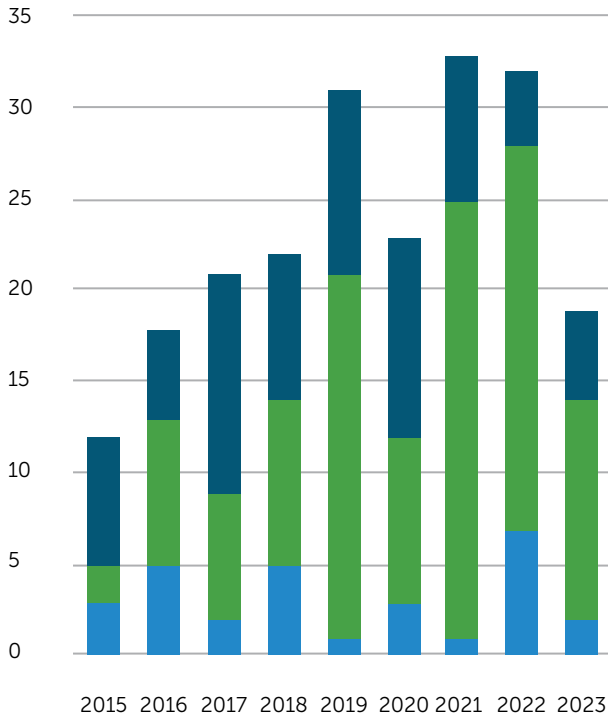
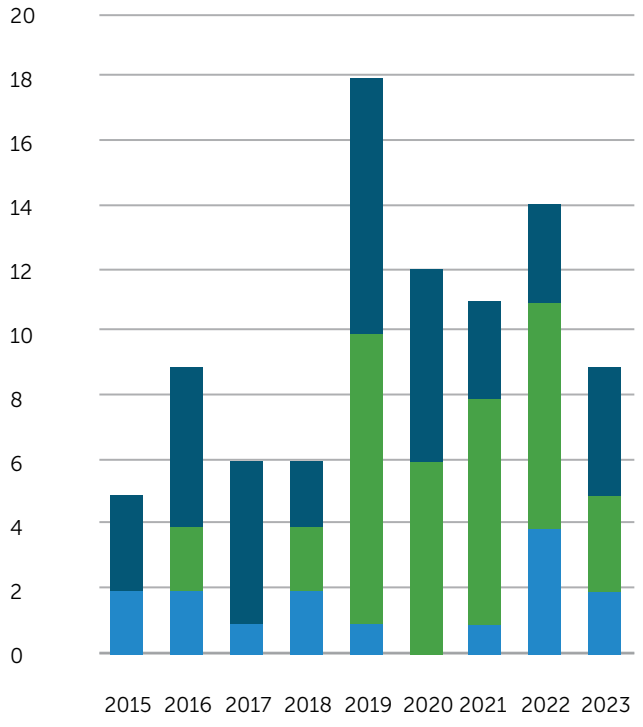
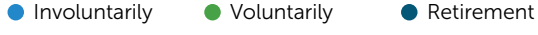



**Figure 4: Rawhide Attrition by Reason**



Platte River projects that it will need to transition approximately 25-30 Rawhide employees at Unit 1's retirement if it backfills vacancies that arise due to retirements or other natural attrition. See Table 1. But Platte River may also fill in for natural attrition with contract labor as Unit 1's retirement date nears. Platte River will be able to better estimate the exact number of employees to transition in future years, as it clarifies the number of employees needed to support the remaining generation at Rawhide and its other departments.

**Table 1. Projected headcount and the number of employees to transition to Rawhide**

| Department | Current headcount<br>As of Jan. 1, 2024 | Target headcount<br>At retirement Dec. 2029 | Target headcount<br>Post 2030 | Employees to transition |
|---|---|---|---|---|
| Plant operations | 31 | 22 | 10-15 | 7-12 |
| Mechanical maintenance | 14 | 8 | 6 | 2 |
| Instrumentation and electrical | 12 | 12 | 4 | 8 |
| Fuel handling / facilities | 12 | 5 | 4 | 1 |
| Engineering | 10 | 7 | 2 | 5 |
| Lab | 2 | 2 | 2 | 0 |
| CAD | 1 | 1 | 0 | 1 |

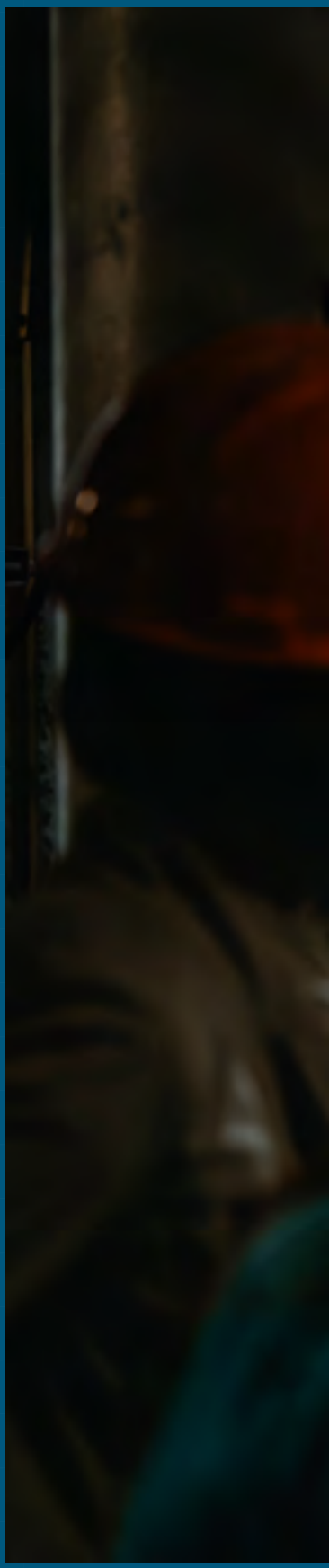
**Current headcount**
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

**Target headcount (at retirement)**
This is the estimated number of employees needed to safely operate Rawhide Unit 1 and the existing combustion turbines.

**Target headcount (post-2030)**
This represents the number of employees that it estimates are needed to run the existing gas combustion turbines at Rawhide after Unit 1 retires. These estimates may be updated in future filings.

**Employees to transition**
This number represents employees whose existing jobs may be eliminated due to Unit 1's retirement. Therefore, this is the number of employees to retrain, transfer within other business areas, or otherwise transition as part of the Just Transition Plan.

Platte River is committed to finding opportunities for each of these employees to remain with the organization, if desired. Platte River intends to honor its promise that no employees will be laid off or involuntarily separated solely due to Unit 1's retirement and the energy transition. How Platte River intends to meet this commitment is discussed further in the principles below.

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# PRINCIPLE 3: WORKFORCE OPPORTUNITIES





Platte River management will prioritize internal staff for workforce opportunities where Rawhide employees have relevant qualifications and experience.

To implement this principle, Platte River is identifying growth opportunities and projected work for existing employees to transition at Rawhide and at Headquarters. The main areas where Platte River sees these opportunities are:

- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

Each of these areas is anticipated to grow between now and 2029 due to the energy transition and Platte River's entry into RTO–West. Platte River encourages high-performing employees to reach out to their supervisors (either as part of a scheduled performance discussion or at other times) to discuss potential transition plans and opportunities. Platte River advertises all vacancies to internal employees and seeks to prioritize internal applicants for many of its open positions.

Platte River plans additional formal efforts in the upcoming years to highlight potential growth opportunities within the organization and support employee advancement and retention. These efforts include an internal "career fair" (expected in 2026) to showcase potential opportunities within the organization and to further the dialogue between departments that may lose staff and departments that need additional employees. Platte River also plans a "shadowing" program between Rawhide and headquarters so that Rawhide employees may learn more about headquarters positions that may be available, and the knowledge, skills, or abilities needed for those roles.

No later than year end 2028, Platte River plans to start formal interviews with employees to have more in-depth discussions about their goals and determine how they may align with future roles. These formal interviews will also help Platte River determine what training, education, or other support might be needed to successfully transition employees into future growth roles.

# PRINCIPLE 4: WORKFORCE TRAINING



Platte River management will provide workforce training for Rawhide employees when appropriate to allow them to successfully transition into new roles.

To implement this principle, Platte River will use the career fair, shadowing, and interview programs described above to engage with employees on how Platte River can best help employees meet their career goals.  Platte River intends to capture and analyze information learned through annual employee evaluation processes and other discussions to identify employment trends and skill gaps and to formalize training programs that are specific to the identified skill needs post-2029.

Platte River understands that training and education may be a large component of the workforce transition, particularly for employees contemplating career changes. Platte River currently has a tuition reimbursement program for employees who want to increase skills. This program is already in use with a current Rawhide employee taking courses in information technology. Platte River anticipates this program will grow significantly as it identifies skill gaps and helps employees chart career paths. Platte River is working with its staff to increase transferable skills (like computer literacy) in its current workforce. Platte River will also explore partnerships with local educational institutions in northern Colorado and southern Wyoming.These partnerships may include formal training programs tailored to the Rawhide transition or a continuation of the current tuition reimbursement program, depending on employee and Platte River needs.







# PRINCIPLE 5: RETENTION STRATEGIES

Platte River management will evaluate, design, and implement employee retention strategies to ensure Rawhide Unit 1 continues to provide safe, reliable and financially responsible energy to its owner communities until its closure date.

Platte River is committed to implementing this principle for transitioning Rawhide employees. But employee retention is not just a concern as part of the energy transition or the Just Transition Plan. Platte River seeks to be a leading employer to drive retention for all employees, at both Rawhide and headquarters, and has made many recent changes to its compensation and total employee rewards programs to support employee retention. These changes include industry-leading total rewards and compensation packages, such as:

- Platte River family leave program (providing 12 weeks fully paid family leave),
- Platte River's compensation philosophy is inclusive of a compensation study which uses a market-leading pay above the 50th percentile in 2024,
- Platte River's employee-focused benefits program, and
- Hybrid and remote work available for certain roles.

Platte River is exploring other options for retention at Rawhide up to transition, including retention bonus programs and incentives for advance retirement planning in the years leading up to Unit 1's closure. Platte River will work with its employees to evaluate and carefully implement these strategies in a way that supports the goals of continued operational excellence at Rawhide, an orderly and well planned closure, and employee transition to new roles.



# PRINCIPLE 6: TRANSITION SUPPORT



For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

When discussing this principle, it is important to reiterate that current projections show few, if any, non-voluntary transitions due to the retirement of Rawhide Unit 1. As discussed in the first five principles, above, Platte River is committed to retaining its workforce and anticipates finding roles for Rawhide employees who want to transition to new roles after 2029. Platte River does not anticipate layoffs or other mass transitions. Platte River's Just Transition Plan supports an individualized and career-focused approach for each employee affected by Unit 1's closure.

Should any non-voluntary transitions be needed in the future due to Unit 1's retirement, Platte River is committed to supporting those employees as it supports those who transition voluntarily. Efforts will be deployed through career path discussions and ongoing training and education opportunities like those provided to employees transitioning to internal Platte River roles. Platte River also provides an employee assistance program, which is available to current employees contemplating career changes and transitions. This program may include counseling support as well as legal or financial advice to assist employees in making life changes.

# CONCLUSION

Platte River is committed to a just transition and to retaining its staff and culture of operational excellence. This document will be updated as its workforce plans evolve. Platte River will remain committed to the principles outlined by its board and management to demonstrate their unwavering support to the Platte River employees that safely and reliably operate Unit 1, its highest-performing and most cost-effective resource. Platte River looks forward to working with its staff, management, and the Office of Just Transition to responsibly move toward its energy future.





# **Appendix C:** Board resolution for 2024 IRP approval

# RESOLUTION NO. 07-24

## Background

A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.

B. Platte River is obligated by contract to serve the owner communities' wholesale electrical capacity and energy needs through 2060.

C. Platte River and its owner communities collaborate to conduct supply-side and demand-side planning.

D. Platte River uses integrated resource planning to support its development of a resource portfolio consistent with its three foundational pillars of reliability, environmental responsibility and financial sustainability.

E. In 2018, the board of directors (board) adopted the Resource Diversification Policy, which directs Platte River's general manager/CEO to proactively work toward the goal of reaching a 100% non-carbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

F. By law and to remain eligible for federal hydropower allocations, Platte River must submit a formal integrated resource plan (IRP) to the Western Area Power Administration every five years. Given the challenges of quickly advancing the board's Resource Diversification Policy goals, compounded by rapid evolution of utility technology, the board encouraged staff to accelerate its formal IRP development process. Platte River staff completed and submitted its most recent IRP in 2020, and shared with the board an informal update to the IRP inputs and assumptions in 2022.

G. Platte River staff, collaborating with industry experts, has worked over the past 18 months to develop the 2024 IRP with updated studies, assumptions, technology advancements, and modeling inputs. Platte River supported community engagement through numerous in-person and virtual meetings, cataloguing and responding to stakeholder questions, and a dedicated internet microsite. Staff shared background information for the 2024 IRP with the board in April 2024 and presented a full draft of the 2024 IRP at the May 2024 board meeting.

H. The 2024 IRP reflects existing and potential future resources based on current information, technology and system capabilities and recognizes these and other factors will continue to evolve.

I. Staff recommends selection of the 2024 IRP's optimal new carbon portfolio to establish a new baseline for planning, budgetary and ratemaking purposes.

J. The optimal carbon portfolio in the 2024 IRP provides a path for Platte River to reduce its carbon emissions by more than 90% from 2005 levels while maintaining reliability and financial sustainability, and is therefore consistent with the Resource Diversification Policy and surpasses Colorado legislative goals for greenhouse gas reductions.

K. Staff expects to prepare an updated IRP by 2028, while continuing to communicate transparently and foster public engagement in Platte River's long-term resource planning activities.

L. The board intends that when it approves the Just Transition Plan (Resolution 08-24) for the closure of Rawhide Unit 1, the Just Transition Plan will become part of the 2024 IRP.

Resolution

The board of directors of Platte River Power Authority therefore resolves that:

1. The 2024 IRP, as contained in the July 2024 meeting packet, is approved, and
2. Staff's recommendation to select the optimal new carbon portfolio as Platte River's new baseline for planning, budgetary and ratemaking purposes is accepted, and
3. When the board approves Platte River's Just Transition Plan for Rawhide Unit 1, the Just Transition Plan becomes part of the 2024 IRP.

AS WITNESS, I have signed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this 25 day of July 2024.

Secretary

Adopted: July 25, 2024
Vote: 6-0

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

www.prpa.org

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit FF: PRPA, *Craig Units 1&2 (Yampa Project)* (2026)

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# Craig units 1 & 2 (Yampa Project)



**Fuel type:** coal
**Net capacity:** 151 MW
**Commercial operation:** Unit 1—1980; Unit 2—1979
**Operations:** baseload

## Operations

- Platte River's ownership of Craig 1 and 2 is 18%
- Operated by Tri-State Generation and Transmission
- Co-owners include Tri-State Generation and Transmission, Salt River Project, PacifiCorp and Xcel Energy
- Craig Unit 1 to be removed from Platte River's mix by Dec. 31, 2025
- Craig Unit 2 to be removed from Platte River's mix by Sept. 30, 2028

## Financials

- Platte River's second-lowest operating cost resource
- Fuel prices are based on production costs and not subject to market price volatility
- No debt service
- Fuel cost volatility mitigated by management of mine production levels and costs through an ownership share of Trapper Mine (27.14%), located adjacent to Craig units 1 and 2

## Environmental

- Upgraded technology to reduce sulfur and particulate emissions
- Maintains full compliance with strict environmental laws and regulations

**Accessibility Notice:**
Per the Americans with Disabilities Act (ADA), Platte River Power Authority will provide reasonable accommodation to qualified individuals with a disability who need assistance. Please email us at communications@prpa.org or call 970-226-4000. "Walk-in" requests for auxiliary aids and services may be honored to the extent possible but can be unavailable if advance notice is not provided.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit GG: PacifiCorp, *Utah Integrated Resource Plan Volume I* (Mar. 31, 2025)

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# UTAH 2025
## Integrated Resource Plan

Volume I - March 31, 2025






PacifiCorp

*This 2025 Integrated Resource Plan is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.*

For more information, contact:
PacifiCorp Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
irp@pacificorp.com
www.pacificorp.com

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# CHAPTER 13 – UTAH ACTION PLAN

# CHAPTER 1 – EXECUTIVE SUMMARY

## Maintaining customer focus

Our 2025 Integrated Resource Plan (IRP) is a roadmap for continual progress in safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

### Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.

- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

**New Resources**

- The following resources are added in the 2025 IRP:
  - 3,782 megawatts of new wind resources
  - 7,524 megawatts of storage resources, including four-hour, and 100-hour durations
  - 5,912 megawatts of new solar resources, including utility-scale and small-scale
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

**Customer Programs**

- 5,255 megawatts of capacity saved through energy efficiency programs
- 769 megawatts of capacity saved through direct load control programs

**Transmission**

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Yakima substation near Yakima, Washington
- Various upgrades that increase transfer capability between the Summer Lake substation in Oregon and the Hemingway substation in Idaho

- New transmission, including a 110-mile line from Summer Lake to Burns, Oregon, and an 88-mile line from Summer Lake to the planned Full Circle substation in Central Oregon. These near-term upgrades connect with a later upgrade a new transmission line connecting Walla Walla to the Full Circle substation, expected in 2039.
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

**Key Thermal Outcomes**

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030 to comply with Wyoming's low carbon portfolio standard
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Initiate the process of coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

## PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are situs-allocated and deliverable to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[1] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements were represented:

- Utah, Idaho, Wyoming, and California (UIWC)[2]
  - Cost-effective resources
  - Includes WRAP compliance constraints for UIWC load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Includes WRAP compliance constraints for Oregon load
  - Includes small-scale renewable capacity requirement
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and assumed to be situs to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of this draft necessitated that coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off,

[1] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[2] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

PacifiCorp hosted stakeholders in nine online public input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 1.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

**Figure 1.1 – Key Elements of PacifiCorp's 2025 IRP Approach**



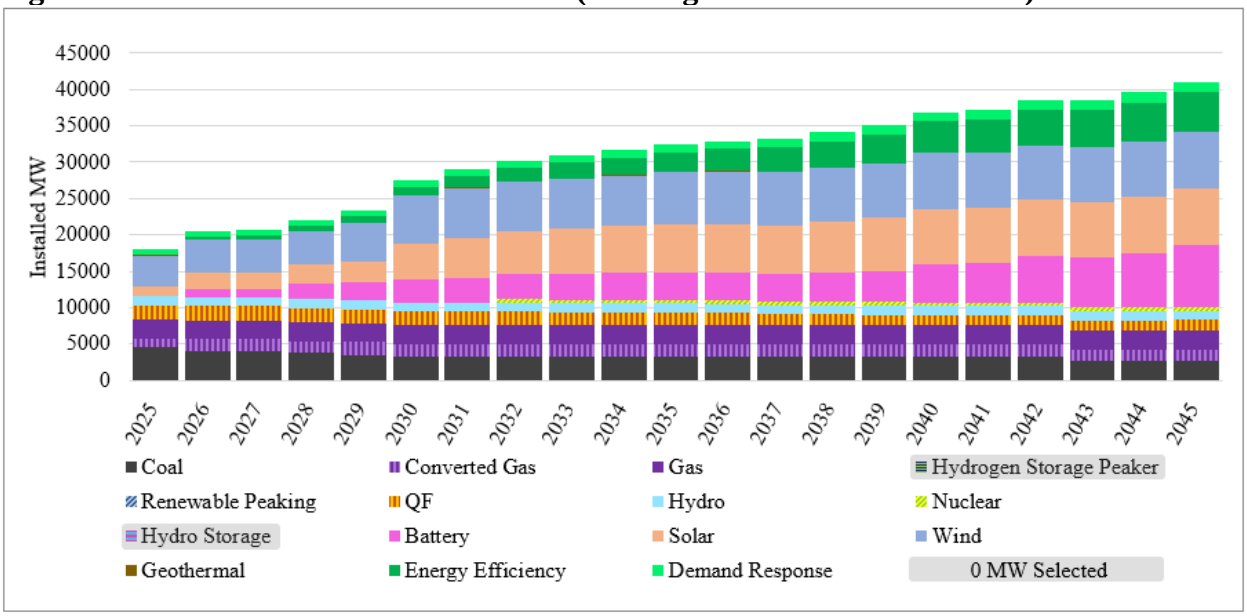

## Preferred Portfolio Highlights

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and renewable peaking resources facilitated by incremental transmission investments.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the fall of 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912MW of new solar.

**Figure 1.2 – 2025 IRP Preferred Portfolio (Existing and Planned Resources)***




* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The 2025 IRP preferred portfolio includes several transmission upgrades which increase transfer capability between southern Utah and the Wasatch Front and between Walla Walla and Yakima in Washington, as well as a series of upgrades that increase transfer capability between the Hemingway substation in Idaho, the Summer Lake Substation in southern Oregon, the planned Full Circle substation in Deschutes County, Oregon, and eventually connecting from Full Circle to Walla Walla in Washington. Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 1.1 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio. Currently, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

**Table 1.1 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]**

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| **2026** | Utah South - Wasatch Front: 138 kV reinforcement #1 | 250 | 250 | 250 | 30 | 100% | Utah South | Wasatch Front |
| **2028** | Cluster 1 Area 11: Willamette Valley | 0 | 0 | 199 | 14 | 100% | n/a | n/a |
| | Cluster 1 Area 14: Summer Lake | 400 | 400 | 400 | 111 | 100% | Summer Lake | Hemingway |
| | Cluster 1/2/3: Walla Walla | 0 | 0 | 393 | 328 | 100% | n/a | n/a |
| | Serial queue: Central Oregon | 0 | 0 | 152 | 4 | 100% | n/a | n/a |
| | Serial/Cluster 1/2: Yakima | 0 | 0 | 628 | 64 | 100% | n/a | n/a |
| | Utah South - Wasatch Front: 138 kV reinforcement #2 | 200 | 200 | 200 | 12 | 100% | Utah South | Wasatch Front |
| **2029** | Cluster 2 Area 23: Willamette Valley | 0 | 0 | 393 | 2 | 100% | n/a | n/a |
| **2030** | Cluster 2 Area 19: Summer Lake to Central Oregon 500 k | 1,500 | 1,500 | 670 | 1,283 | 100% | Summer Lake | Central OR |
| | Walla Walla - Yakima 230 kV | 400 | 400 | 400 | 142 | 100% | Walla Walla | Yakima |
| **2031** | Serial through Cluster 1 Area 13: Southern Oregon | 0 | 0 | 231 | 42 | 100% | n/a | n/a |
| **2032** | Cluster 1 Area 12: Southern Oregon | 0 | 0 | 300 | 303 | 100% | n/a | n/a |
| **2033** | Cluster 2 Area 18: Central Oregon 500 kV Substation | 0 | 0 | 518 | 372 | 100% | n/a | n/a |
| **2039** | Walla Walla - Central Oregon 500 kV | 1,500 | 1,500 | 670 | 1,463 | 100% | Walla Walla | Central OR |
| **Grand Total** | | **4,250** | **4,250** | **5,404** | **4,169** | | | |

[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

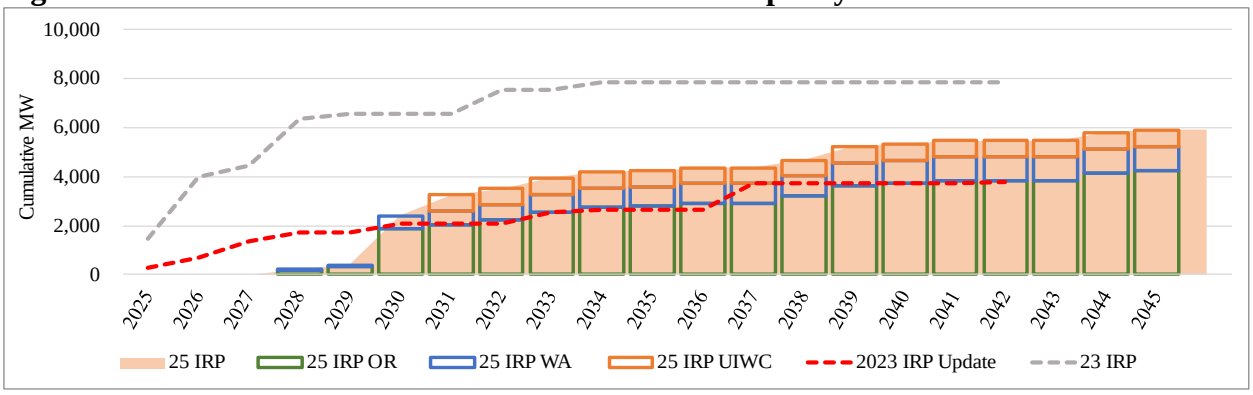
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

In Chapter 9 (Modeling and Portfolio Selection Results), a sensitivity analysis evaluates the impacts of significant new data center loads coming online in the 2027-2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

## New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 1.3.

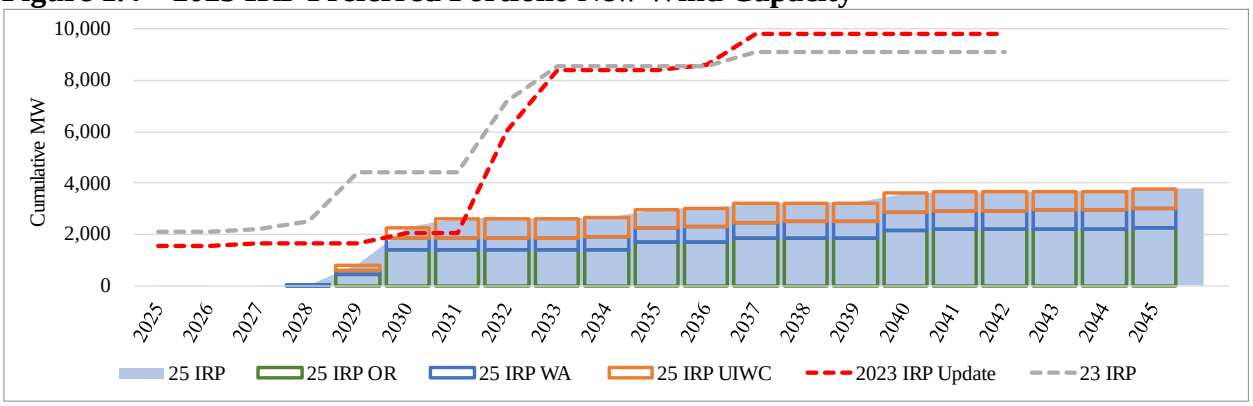
**Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity**



## New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

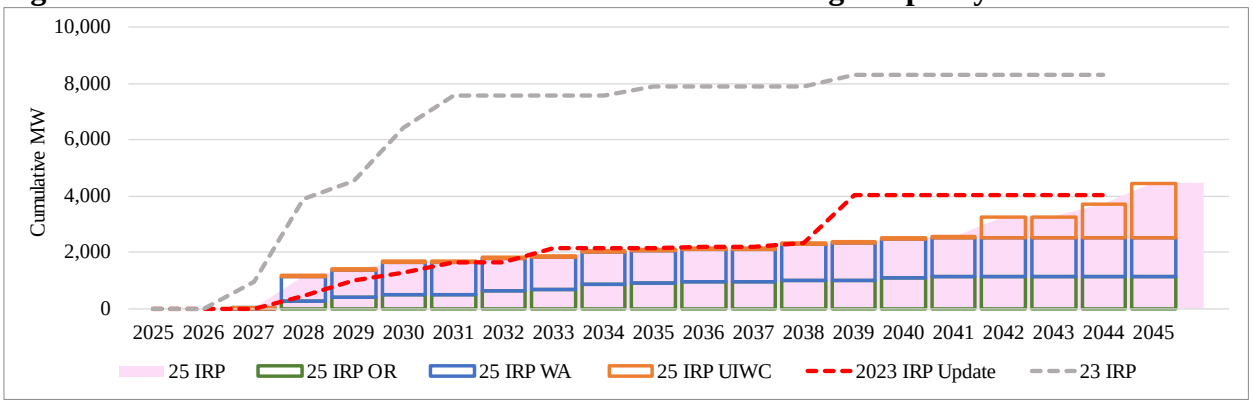
**Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity**




## New Storage Resources

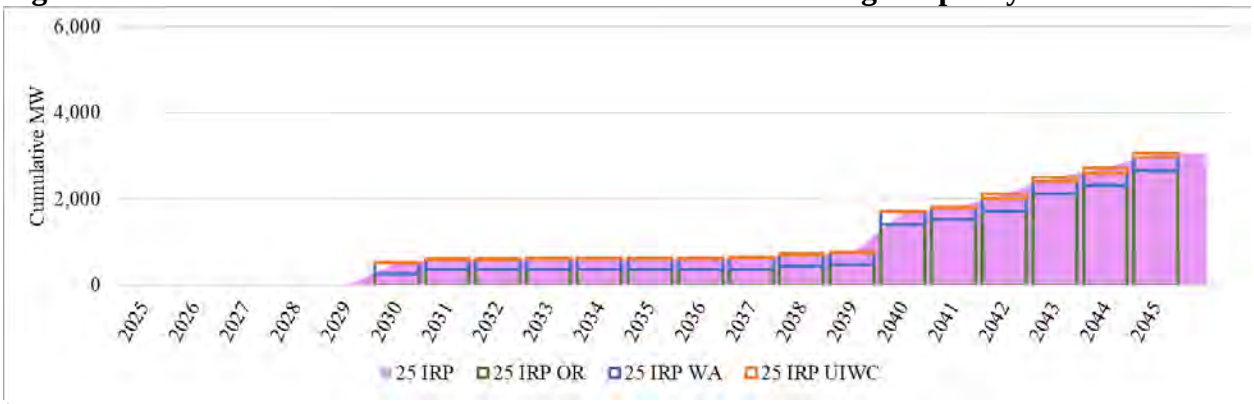
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of 100-hour iron air storage by the end of 2030, 616 MW by 2035 and 3,073 MW by 2045. Total storage selections, inclusive of both 4-hour and 100-hour resources, include a total of 7,524 MW of new storage.

**Figure 1.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]**




[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 1.5 include a minimal amount of intermediate duration storage.

**Figure 1.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]**

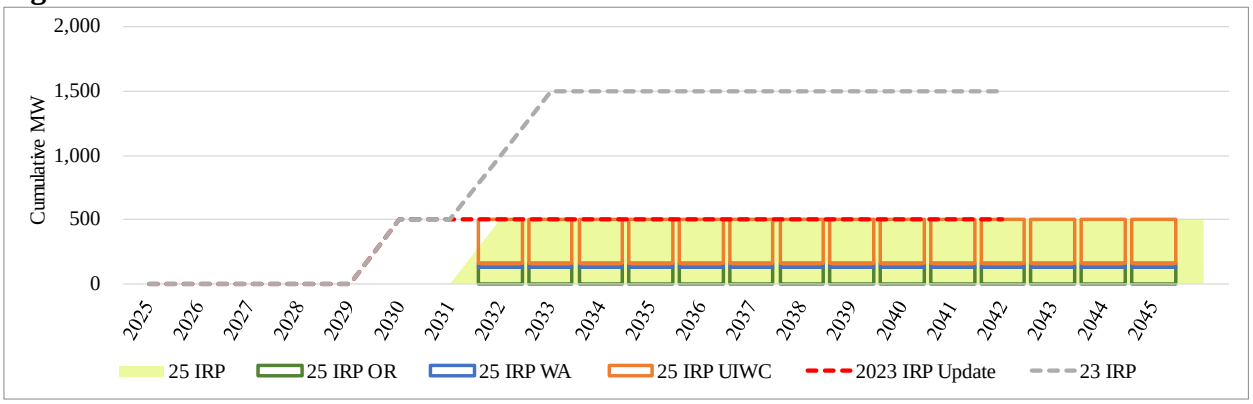



[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

## New Nuclear Resources

The 2025 IRP includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7 , the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031.

**Figure 1. – 2025 IRP New Nuclear[1]**




[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

## Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

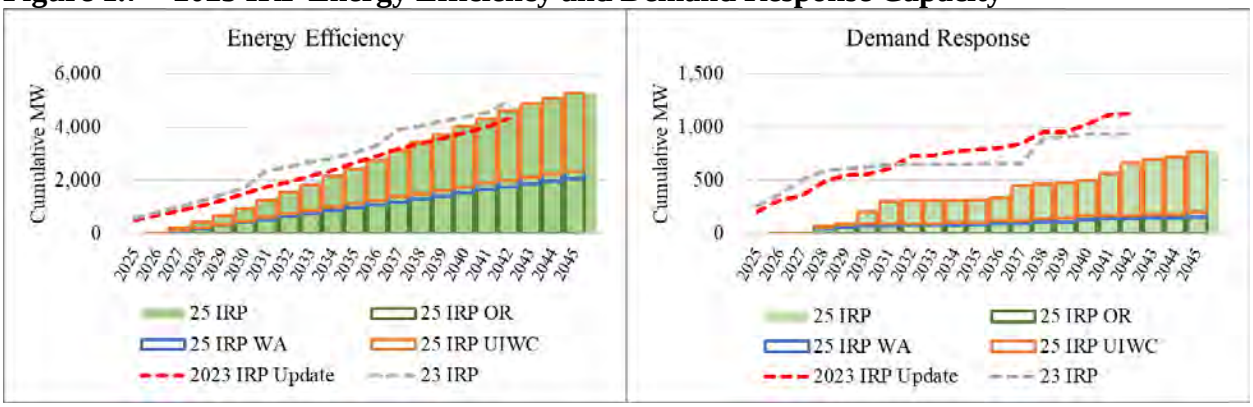
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

and forecasted coincident system peak is down 5.3 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.28 percent for load and 1.18 percent for peak. Changes to PacifiCorp's load forecast are driven by a shift in the 2025 IRP in which demand from new large customers is no longer included in the load forecast as those customers are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits. As shown in Figure 1.8, both energy efficiency and demand response show a lower trajectory in the latest forecast, however the trajectories continue to trend upward across the long-term planning horizon.

- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
  - 610 megawatts of energy efficiency from 2025 through 2028
  - 83 megawatts of demand response from 2025 through 2028

**Figure 1.7 – 2025 IRP Energy Efficiency and Demand Response Capacity**

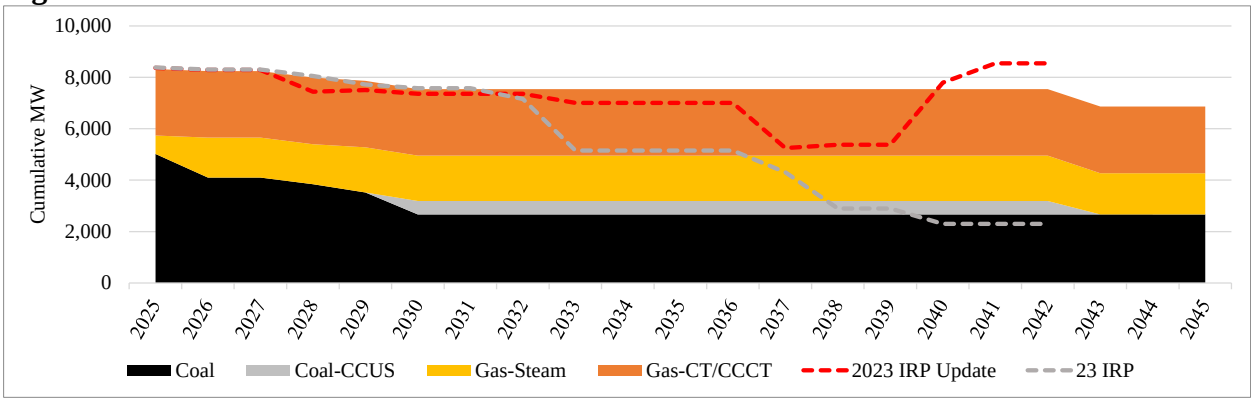



## Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled the company to reduce fuel consumption and associated costs and emissions and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 1.9, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, exits PacifiCorp's share in 386

MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

**Figure 1. – 2025 IRP Preferred Portfolio Thermal Resources**




A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP preferred portfolio is shown in Table 1.2. Also shown in Table 1.2 are the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

**Table 1.2 – 2025 IRP Coal Resource Results Summary**

| Majority-Owned Coal | | | |
|---|---|---|---|
| Unit | 2025 IRP Retirement Year | | 2023 IRP Retirement Year |
| | Selected w/o 111(d) Regulation | Selected w/ 111(d) Regulation | As Selected |
| Dave Johnston 1 & 2 | Not retired (Gas conversion 2029) | No change | 2028 |
| Dave Johnston 3 | 2027 (Clean air compliance) | No change | 2027 (Clean air compliance) |
| Dave Johnston 4 | Not retired | Not retired (Gas conversion 2030) | 2039 |
| Hunter 1 | Not retired | 2032 | 2031 |
| Hunter 2 & 3 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Huntington 1 & 2 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Jim Bridger 1 & 2 | Not retired (Gas conversion 2024) | No change | 2037 (Gas conversion 2024) |
| Jim Bridger 3 & 4 | 2042 (CCS conversion 2030) | No change | 2037 (Gas conversion 2030) |
| Naughton 1 | 2042 (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Naughton 2 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Wyodak | Not retired | 2032 | 2039 |

| Minority-Owned Coal | | |
|---|---|---|
| Unit | 2025 IRP Retirement Year | 2023 IRP Retirement Year |
| | As Input | As Input |
| Colstrip 3 | 2025 (Transfer capacity to unit 4) | 2025 (Transfer capacity to unit 4) |
| Colstrip 4 | 2029 (PacifiCorp exit) | 2029 (PacifiCorp exit) |
| Craig 1 | 2025 (Assumed end of life) | 2025 (Assumed end of life) |
| Craig 2 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 1 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 2 | 2027 (Assumed end of life) | 2027 (Assumed end of life) |

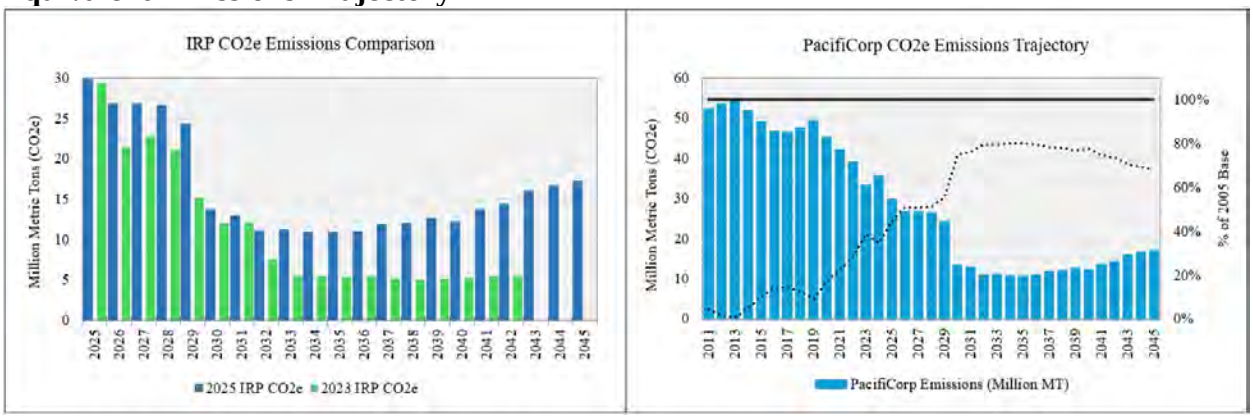
## Carbon Dioxide Emissions

The 2025 IRP preferred portfolio demonstrates PacifiCorp's ongoing commitment to providing cost-effective clean energy solutions for its customers, continuing a trend of declining carbon dioxide ($CO_2$) and $CO_2$ equivalent ($CO_2e$) emissions over the next decade. Key drivers of this decline include PacifiCorp's participation in the Energy Imbalance Market (EIM), the ongoing transition to clean energy resources such as renewables, advanced nuclear, battery storage, and transmission, as well as compliance with Regional Haze regulations.

The chart on the left in Figure 1.10 compares projected annual $CO_2e$ emissions between the 2025 IRP and 2023 IRP preferred portfolios. While the 2025 IRP emissions are projected to be slightly higher than those in the 2023 IRP, this difference stems from updates to modeling assumptions. The expected price-policy scenario in the 2025 IRP does not include a $CO_2$ price or the Ozone Transport Rule, both of which were included in the 2023 IRP. Increased emissions also result from higher unspecified market purchases, assigned a default emissions factor, although market-wide emissions are expected to decline with further renewable energy adoption. PacifiCorp is working with regulators to adjust this factor to reflect the evolving energy market landscape.

The chart on the right in Figure 1.10 presents historical emissions data, assigning emissions to unspecified market purchases, and indicates a long-term decline in system-wide CO2e emissions compared to the company's baseline, with a slight increase toward the end of the planning horizon due to the factors discussed in more detail in Chapter 9.

**Figure 1.8 – 2025 IRP Preferred Portfolio $CO_2$ Equivalent Emissions and PacifiCorp $CO_2$ Equivalent Emissions Trajectory[1]**




[1] PacifiCorp $CO_2$ equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in $CO_2$ equivalent. Market purchases are assigned a default emission factor (0.428 metric tons $CO_2e$/MWh) – emissions from sales are not removed.

## Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 1.3 details specific 2025 IRP action items by resource category.

**Table 1.3 – 2025 IRP Action Plan**

| Action Item | 1. Existing Resource Actions |
|---|---|
| **1a** | **Colstrip Units 3 and 4:**<br>PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030. |
| **1b** | **Craig Unit 1:**<br>PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025. |
| **1c** | **Naughton Units 1 and 2:**<br>PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. |
| **1d** | **Carbon Capture and Storage / Low Carbon Portfolio Standard:**<br>PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. |
| **1e** | **Regional Haze Compliance:**<br>Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. |

| | |
|---|---|
| **1f** | **Natrium™ Demonstration Project:**<br>By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. |
| **1g** | **Ozone Transport Rule Compliance:**<br>EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments. |
| **1h** | **Natural Gas Emissions Compliance Strategies**<br>The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030. |
| **1i** | **Federal Greenhouse Gas Emission Compliance:**<br>EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues. |
| **1j** | **Dave Johnston Units 1 and 2:**<br>PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029. |

| Action Item | 2. New Resource Actions |
|---|---|
| 2a | **Customer Preference Request for Proposals:**<br>PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025. |
| 2b | **2025 All-Source Request for Proposals:**<br>PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3]<br>Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process.<br>Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction. |

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

| Action Item | 3. Transmission Action Items |
|---|---|
| **3a** | **Local Reinforcement Projects**<br>Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids. |
| **3b** | **Gateway West Support**<br>Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. |

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

**Energy Efficiency & Demand Response Targets:**

PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.

PacifiCorp will pursue cost-effective energy efficiency resources.

| Year | First-Year Energy Efficiency (GWh) | Annual Capacity (MW) |
|---|---|---|
| 2025 | 595 | 92 |
| 2026 | 573 | 89 |
| 2027 | 597 | 209 |
| 2028 | 648 | 220 |

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

| Year | Annual Incremental Capacity (MW) |
|---|---|
| 2025 | 18 |
| 2026 | 2 |
| 2027 | 0 |
| 2028 | 63 |

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

| Action Item | 5. Market Purchases |
|---|---|
| 5a | **Market Purchases:**<br>PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:<br>Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.<br>Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.<br>Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions. |

| Action Item | 6. Renewable Energy Credit (REC) Actions |
|---|---|
| 6a | **Renewable Portfolio Standards (RPS):**<br>PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed. |
| 6b | **Renewable Energy Credit Sales:**<br>Maximize the sale of RECs that are not required to meet state RPS compliance obligations. |

# CHAPTER 2 – INTRODUCTION

## CHAPTER HIGHLIGHTS

- PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California.
- This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest.
- Regulatory staff, advocacy groups, and other interested parties influence the development of the IRP through a collaborative public input process.
- As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are made by PacifiCorp with respect to its obligations to customers, regulators, and shareholders.

## INTRODUCTION

In recent integrated resource planning cycles, there has been increased focus on individual state jurisdictional outcomes aligned with both stakeholder and regulatory interest, and state legislation and rulemaking. To recognize and respect this trend, PacifiCorp's 2025 IRP enhances jurisdictional portfolio development and reporting leading to the integration of results into the preferred portfolio. Chapter 8 (Modeling and Portfolio Evaluation) describes the fundamental methodologies used to arrive at state-level initial portfolios and how they are subsequently integrated to form a single coherent plan.

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Chapter 9 (Modeling and Portfolio Selection Results), shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources (including iron-air technology with 100- hour storage duration), and advanced nuclear.[1]

The 2025 IRP preferred portfolio is in addition to contracted resources, many of which are in Utah. The 100 MW Hornshadow I Solar and 200 MW Hornshadow Solar II facilities are set to come online in 2025, while two facilities combining solar and storage are set to come online in 2025 and 2026: Faraday with 525 MW solar and 150 MW storage and Green River with 400 MW solar and 400 MW storage. Finally, Oregon's Community Solar Program has ten small-scale solar facilities scheduled to come online in 2025 and 2026, totaling approximately 18 MW.

The 2025 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 5,492 MW of new solar and 7,668 MW of new storage resources.

New storage includes five battery facilities totaling 520 MW are projected to come online ahead of the peak summer season in 2026: Dominguez BESS (200 MW), Enterprise BESS (80 MW),

[1] See Chapter 7 (Resource Options)

Escalante BESS (80 MW), Granite Mountain BESS (80 MW) and Iron Springs BESS (80 MW). These signed battery storage contracts were committed since the filing of the 2023 IRP update.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission projects which are described in Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant analysis to support the 2025 IRP includes:

- An updated demand-side management resource conservation potential assessment
- A distributed generation study for PacifiCorp's service territory
- A flexible reserve study
- An updated plant water consumption study
- An energy storage potential evaluation
- An assessment of grid enhancement technologies
- Historic weather years
- An updated load and resource balance

This chapter outlines the components of the 2025 IRP, summarizes the role of the IRP, and provides an overview of the public input process.

## 2025 Integrated Resource Plan Components

The basic components of PacifiCorp's 2025 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities; Volume I, Chapter 4 (Transmission)
- Regional resource adequacy assessments, wildfire mitigation planning and the role of transmission in system reliability and incident recovery; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance)
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options)
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results)
- Presentation of PacifiCorp's 2025 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan)

The IRP appendices, included as Volume II, contain the items listed below:

- Load Forecast (Volume II, Appendix A)
- Regulatory Compliance (Volume II, Appendix B)
- Public Input Process (Volume II, Appendix C)
- Demand-Side Management (Volume II, Appendix D)
- Grid Enhancement (Volume II, Appendix E)
- Flexible Reserve Study (Volume II, Appendix F)
- Plant Water Consumption Study (Volume II, Appendix G)
- Stochastics (Volume II, Appendix H)
- Capacity Expansion Results (Volume II, Appendix I)
- Capacity Contribution (Volume II, Appendix K)
- Distributed Generation Study (Volume II, Appendix L)
- Stakeholder Feedback Forms (Volume II, Appendix M)
- Washington Clean Energy Action Plan (Volume II, Appendix O)
- Oregon Clean Energy Update (Volume II, Appendix P)
- Renewable Portfolio Implementation Plan (Volume II, Appendix R)
- Acronyms (Volume II, Appendix Z)

PacifiCorp is also providing supporting workpapers for the 2025 IRP. These electronically provided materials support and provide additional details for the analysis described within the document. Supporting workpapers are generated for public, confidential, and highly confidential data to be provided as appropriate to each recipient. Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. The "Highly Confidential" workpaper category, adopted in the prior 2023 IRP planning cycle, allows the company to provide the maximum amount of access to parties who are not participants in commercial developments or otherwise have direct conflicts of interest regarding commercially sensitive information.

## The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP establishes a proxy resource plan capable delivering adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[2] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

[2] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long-run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

## Public Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized held nine public input meetings, spanning one or two days each, to facilitate information sharing, collaboration, and expectations for the 2025 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage is accessible using the following link:

www.pacificorp.com/energy/integrated-resource-plan.html

Messages relevant to PacifiCorp's IRP can sent to the following email address:

irp@pacificorp.com

Additionally, a stakeholder feedback form provides opportunities for stakeholders to submit additional input and ask questions throughout the 2025 IRP public input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website:

www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summaries of stakeholder feedback forms received, and company responses were provided throughout the public input meeting series and are also available in Appendix M (Stakeholder Feedback Forms). In the 2025 IRP, links to stakeholder feedback forms are provided in footnotes to further tie together stakeholder feedback with the development of the filed IRP. Appendix C (Public Input Process) reports additional details regarding engagement for the 2025 IRP.

# CHAPTER 3 – PLANNING ENVIRONMENT

## CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. Flexible generation, transmission, new storage technologies, and market design changes will need to better integrate these resources into the grid.
- The federal Inflation Reduction Act (IRA) was enacted on August 16, 2022,, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2025 IRP studies. As of December 2024, the future of some provisions of the IRA remains unknown under the new administration.
- 2024 saw significant new environmental regulation with potential impacts to PacifiCorp's generation resources. These included Greenhouse Gas (GHG) emission standards for existing coal-fired and new gas-fired plants, Mercury and Air Toxics Standards (MATS) revisions, Effluent Limitations Guidelines revisions, Coal Combustion Residuals legacy rule, and the NEPA Phase 2 rule.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of retail electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its inaugural Clean Energy Implementation Plan (CEIP) in December 2021, and expects to file its second CEIP in October 2025, detailing the company's action plan for the next four-year period.
- In 2021, Washington passed the Climate Commitment Act, which established a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2025 IRP includes modeling to support House Bill 2021 which will be expanded upon in PacifiCorp's Oregon Clean Energy Plan submission to be filed within 180 days of the 2025 IRP.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM's footprint has grown significantly, generating $3.4 billion in monetary benefits to customers of participating entities. ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing

authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

## Introduction

This chapter profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the role of emerging technologies, and the net costs of renewables and battery technologies also factor into the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

## Wholesale Electricity Markets

PacifiCorp's system operates in conjunction with a multifaceted market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers' expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits and improved technology performance have continued to place wind and solar energy generators "in the money" in areas of high resource potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, evolving storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These transmission lines ultimately connect areas of high renewable energy potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project, brought in-service in late 2024. These transmission projects will provide greater system-wide flexibility transferring energy from Wyoming to load centers located in Utah.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. As of 2022, nine states had implemented energy storage targets or mandates, with action being considered in at least one other.[1] In California, the Elkhorn Battery project became fully operational for Pacific Gas & Electric (PG&E) in April of 2022. The Moss Landing project in Monterey County includes 182.5 MW of Tesla Megapack energy storage.[2] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Utah, Hawaii, Arizona, Nevada, California, and Texas.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[3]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barriers to the participation of electric storage resources in certain organized wholesale markets. PacifiCorp continues to evaluate the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance Market (EIM). The EIM became operational November 1, 2014, and since that time has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho

[1] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.
[2] In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; PG&E ushers in landmark Tesla battery energy storage system at Moss Landing (mercurynews.com)
[3] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico, Avista Utilities, Tucson Electric Power, Turlock Irrigation District, Tacoma Power, Bonneville Power Administration, Avangrid Renewables, El Paso Electric, and Western Area Power Administration join the EIM. Black Hills Power plans to join the EIM in 2026. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Extended Day-Ahead Market (EDAM), which is currently in the phase of implementation activities and expected to onboard participants in 2026.

As with all markets, electricity markets face a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented 24.1% decline in marketed natural gas production in Texas, a drop of 186.7 billion cubic feet (Bcf) compared to the previous month. This decline contributed to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

The Western United States experienced an excessive heat event during the first week of September 2022. As a result, record temperatures were recorded on September 4th through September 7th, reaching as high as 114º F in Sacramento, California, 110º F in Burbank, California, and 107º F in Salt Lake City, Utah. With these record setting temperatures, the West saw a widespread surge in electricity demand and correspondingly tight supply conditions. Maintaining reliability across the region during this period was a testament to the benefits of energy markets, geographic diversity across the West, and conservation efforts during extreme heat events.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability, and any number of data services are available that track the status of new resource additions[4]. In NERC's latest release, the WECC region was classified as "elevated risk", in which shortfalls may occur in extreme conditions.

The Western Resource Adequacy Program (WRAP)[5] will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

[4] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment
[5] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan's decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon because of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2025 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide ($CO_2$) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies which drive additional costs and restrictions of emissions. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

## Power Market Prices

Mild weather, strong production, and limited exports caused high storage levels in the fossil gas market, resulting in low gas prices throughout 2024. Low fuel prices coupled with mild demand led to an annually averaged 34% decrease in on-peak spot prices across the Non-CAISO WECC trading hubs in 2024, as seen in Table 3.1.

**Table 3.1 - 2023 and 2024 Monthly Average On-Peak Spot Prices ($/MWh)**

| Month | 2023 | 2024 | Difference | Percent |
|---|---|---|---|---|
| Jan | 135.23 | 137.27 | 2.05 | 2% |
| Feb | 84.41 | 41.95 | -42.46 | -50% |
| Mar | 76.51 | 25.05 | -51.46 | -67% |
| Apr | 79.53 | 18.57 | -60.97 | -77% |
| May | 21.60 | 20.48 | -1.13 | -5% |
| Jun | 38.87 | 31.13 | -7.74 | -20% |
| Jul | 93.02 | 67.88 | -25.13 | -27% |
| Aug | 88.59 | 48.50 | -40.09 | -45% |
| Sep | 51.76 | 52.55 | 0.78 | 2% |
| Oct | 78.57 | 46.24 | -32.33 | -41% |
| Nov | 70.90 | 35.19 | -35.71 | -50% |
| Dec | 52.12 | 47.50 | -4.62 | -9% |
| **Annual** | **72.59** | **47.69** | **-24.90** | **-34%** |

**As of December 16, 2024*

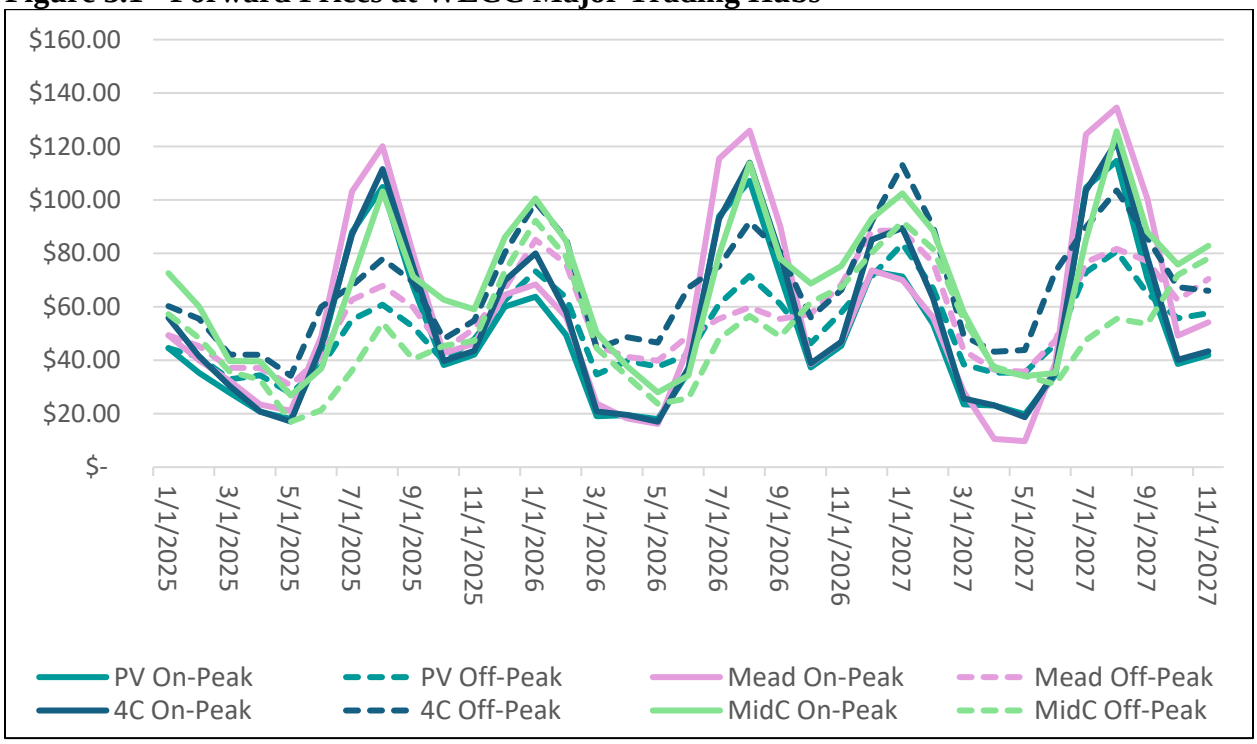
*Source: SNL*

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to increase slightly relative to 2024 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August

[6] California and Washington carbon allowance price forecasts are applied when appropriate. Washington allowance prices assumed the forecast published by Vivid Economics, commissioned by Washington Department of Ecology as part of its CCA Regulatory Impact Analysis for WAC 173-446, which was the best available information at the time of modeling. Available at https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

2025 On-Peak power prices at Palo Verde, Mead, Four Corners, and Mid-Columbia are all trading around $105-$120 per MWh.

**Figure 3.1 - Forward Prices at WECC Major Trading Hubs**




*Source: OTC, Siemens PTI*

Table 3.2 reports the quarterly on-peak and off-peak price spread across the major WECC hubs, driving the peaks and valleys observed in Figure 3.1 above.

**Table 3.2 - 2025-2027 Forward Price Spread ($/MWh)**

| | Palo Verde | | Mead | | 4 Corners | | Mid-Columbia | |
|---|---|---|---|---|---|---|---|---|
| Date | On-Peak | Off-Peak | On-Peak | Off-Peak | On-Peak | Off-Peak | On-Peak | Off-Peak |
| 1/1/2025 | $ 44.57 | $ 44.53 | $ 49.32 | $ 49.35 | $ 55.87 | $ 60.23 | $ 72.60 | $ 57.25 |
| 5/1/2025 | $ 18.04 | $ 27.62 | $ 21.12 | $ 30.62 | $ 17.05 | $ 34.20 | $ 26.81 | $ 17.02 |
| 8/1/2025 | $104.89 | $ 60.81 | $120.14 | $ 67.85 | $111.56 | $ 77.93 | $103.20 | $ 53.99 |
| 11/1/2025 | $ 42.14 | $ 47.94 | $ 46.28 | $ 51.86 | $ 43.55 | $ 54.89 | $ 59.08 | $ 47.28 |
| 1/1/2026 | $ 63.81 | $ 73.32 | $ 68.41 | $ 85.12 | $ 79.99 | $ 99.17 | $100.52 | $ 92.19 |
| 5/1/2026 | $ 17.98 | $ 37.62 | $ 16.18 | $ 39.84 | $ 17.00 | $ 46.59 | $ 27.99 | $ 23.71 |
| 8/1/2026 | $107.13 | $ 71.57 | $125.96 | $ 59.86 | $113.94 | $ 91.72 | $113.74 | $ 56.61 |
| 11/1/2026 | $ 45.38 | $ 57.92 | $ 46.83 | $ 68.32 | $ 46.89 | $ 66.32 | $ 75.27 | $ 67.37 |
| 1/1/2027 | $ 71.36 | $ 83.56 | $ 70.01 | $ 88.44 | $ 89.44 | $113.02 | $102.48 | $ 91.87 |
| 5/1/2027 | $ 19.80 | $ 35.40 | $ 9.73 | $ 35.70 | $ 18.71 | $ 43.83 | $ 34.07 | $ 34.10 |
| 8/1/2027 | $114.63 | $ 80.80 | $134.58 | $ 81.71 | $121.91 | $103.55 | $125.72 | $ 55.51 |
| 11/1/2027 | $ 41.95 | $ 57.62 | $ 54.19 | $ 70.41 | $ 43.35 | $ 65.97 | $ 82.83 | $ 78.10 |

*Source: OTC*

## Power Market Dynamics

### Non-CAISO WECC Generation and Capacity Mix

The generation mix in the non-CAISO WECC region reflects the influence of state RPS (renewable portfolio standard) and emissions policies. In 2023, natural gas resources provided about 31% of generated energy followed by hydro at 22%, coal at 18%, and wind at 12%. Natural gas and coal share is expected to decrease slightly, with non-hydro renewables expected to replace this energy throughout 2030.

**Figure 3.2 - National RPS Targets**

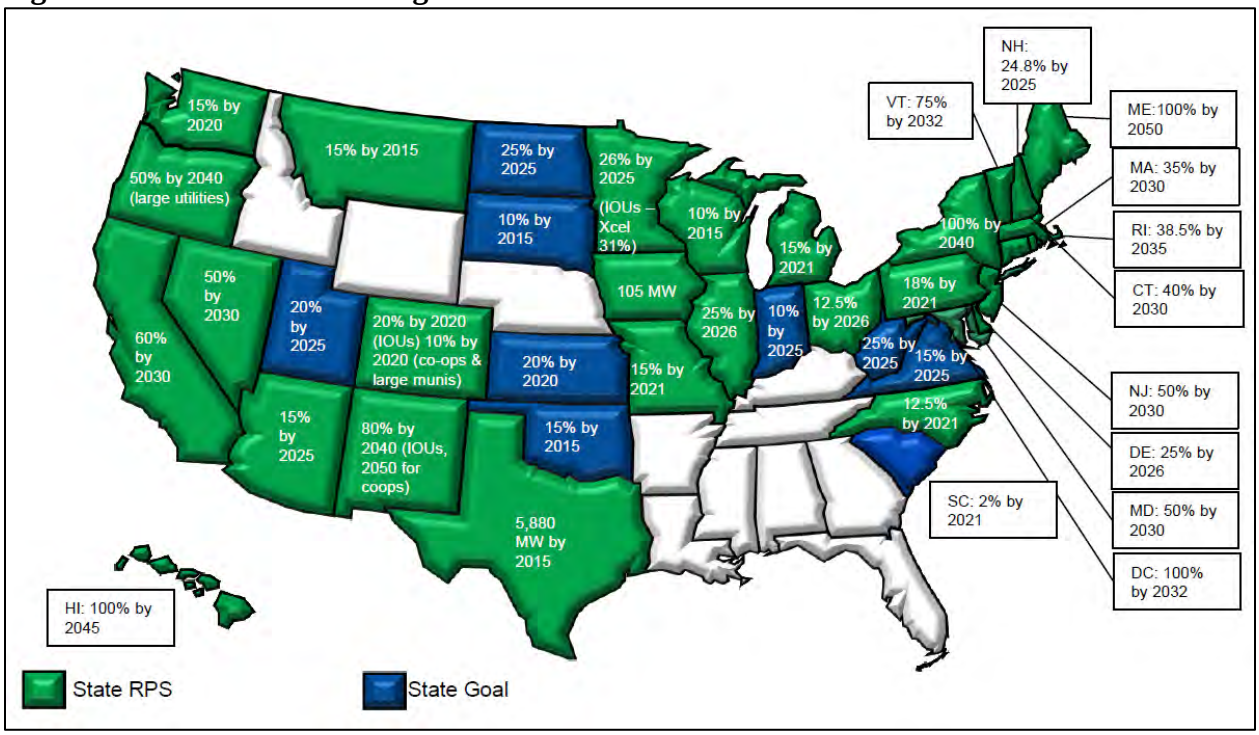
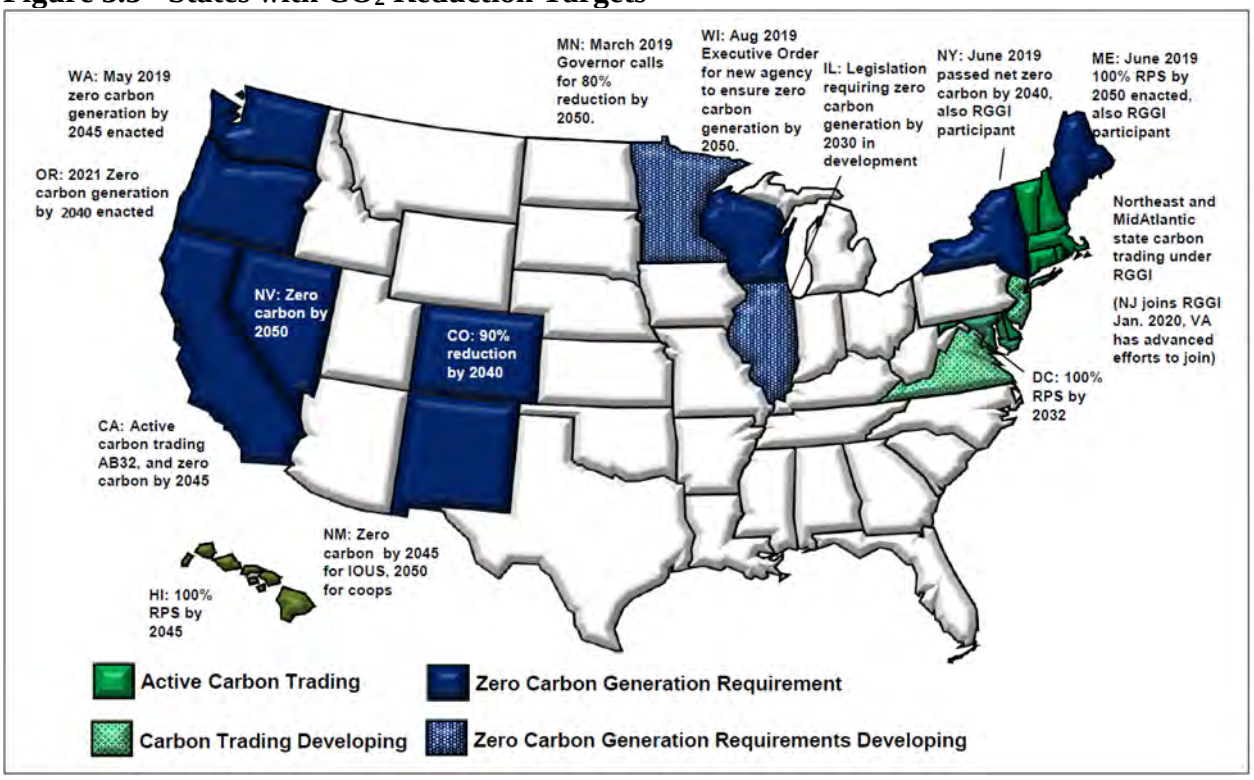
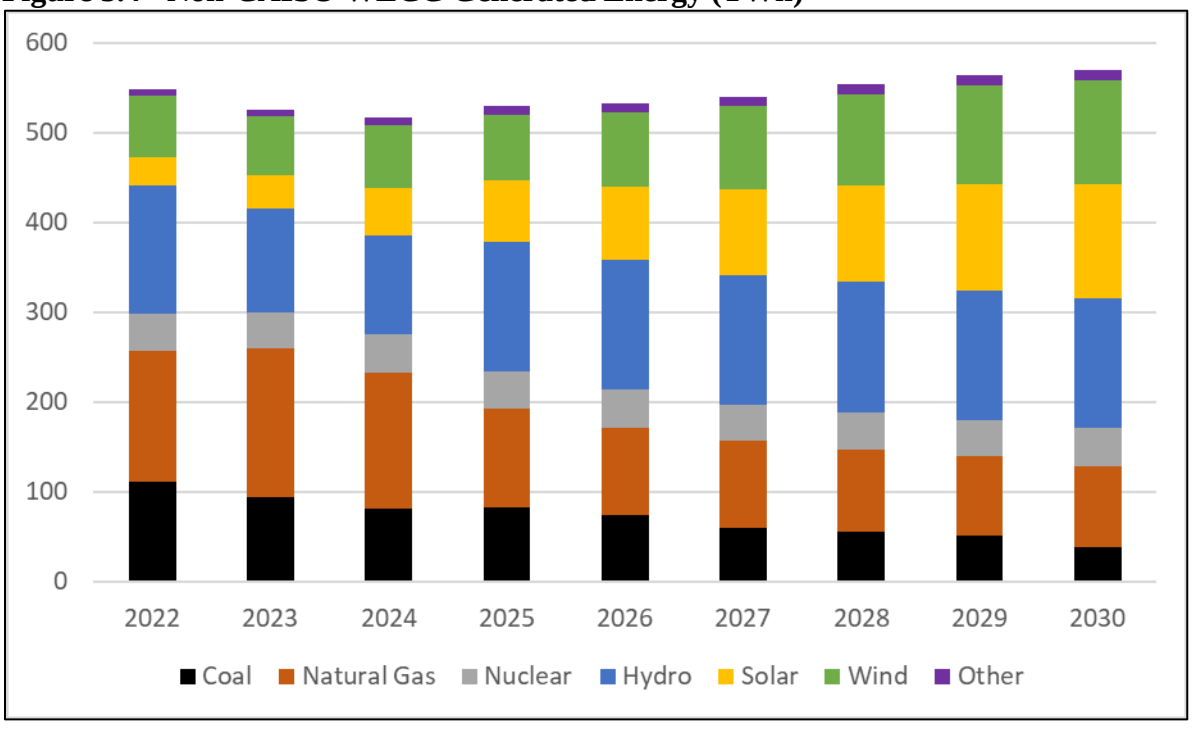


**Figure 3.3 - States with $CO_2$ Reduction Targets**




*Source: Siemens PTI*

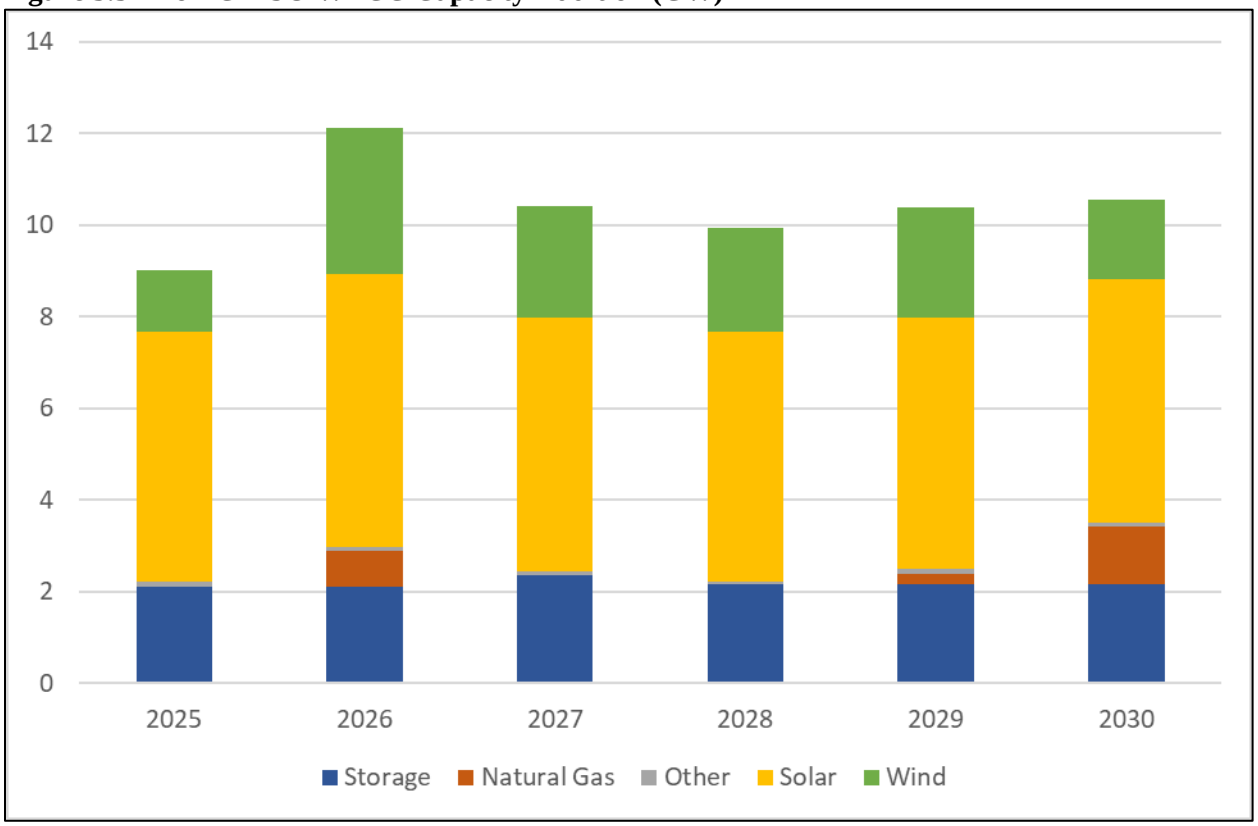
**Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)**




*Source: IHS Markit, SNL, Siemens PTI*

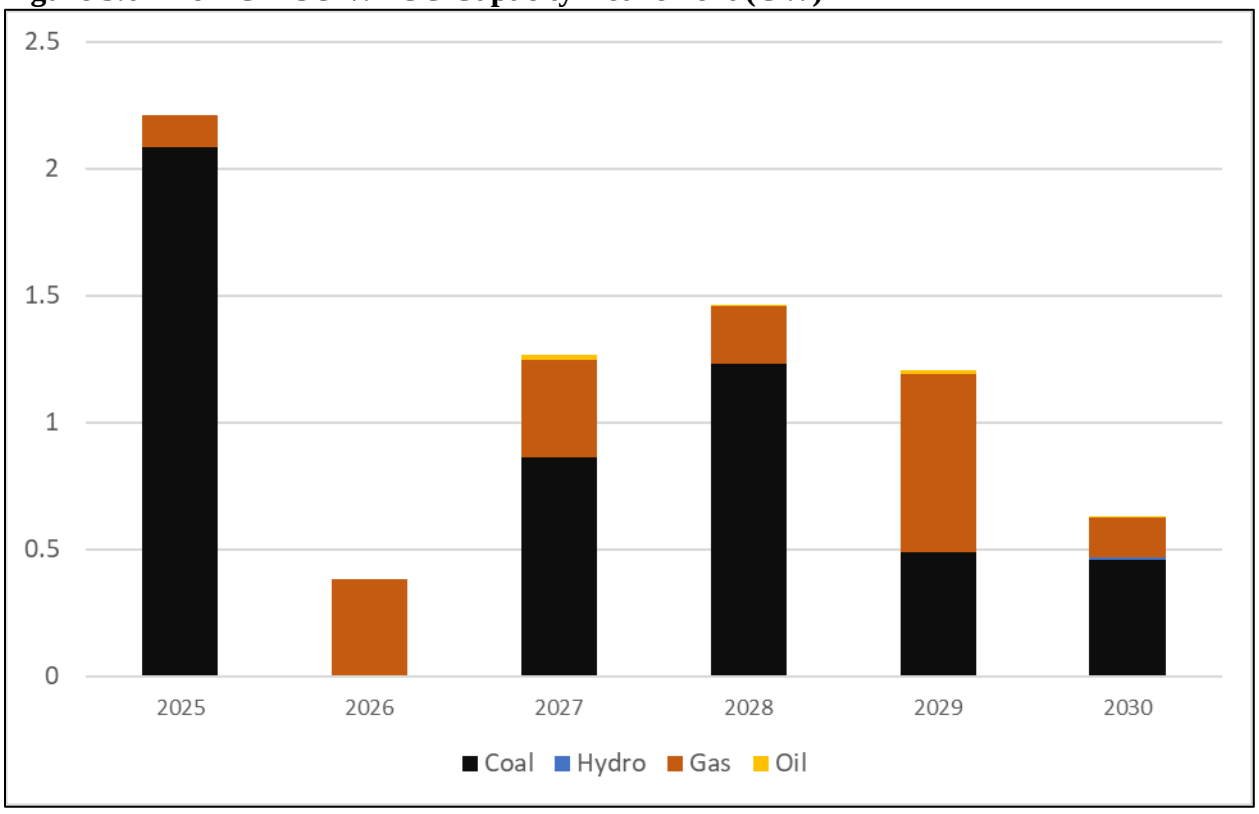
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage capacity additions have also been significant, with 1.4 GW of storage capacity brought online in 2022 and 1.9 GW online through October 2024. Minimal fossil fuel capacity came online in 2023, and that trend may continue through 2030 if carbon reduction goals continue to drive renewable additions.

**Figure 3.5 - Non-CAISO WECC Capacity Addition (GW)**




*Source: IHS Markit, SNL, Siemens PTI*

**Figure 3.6 - Non-CAISO WECC Capacity Retirement (GW)**




*Source: IHS Markit, SNL, Siemens PTI*

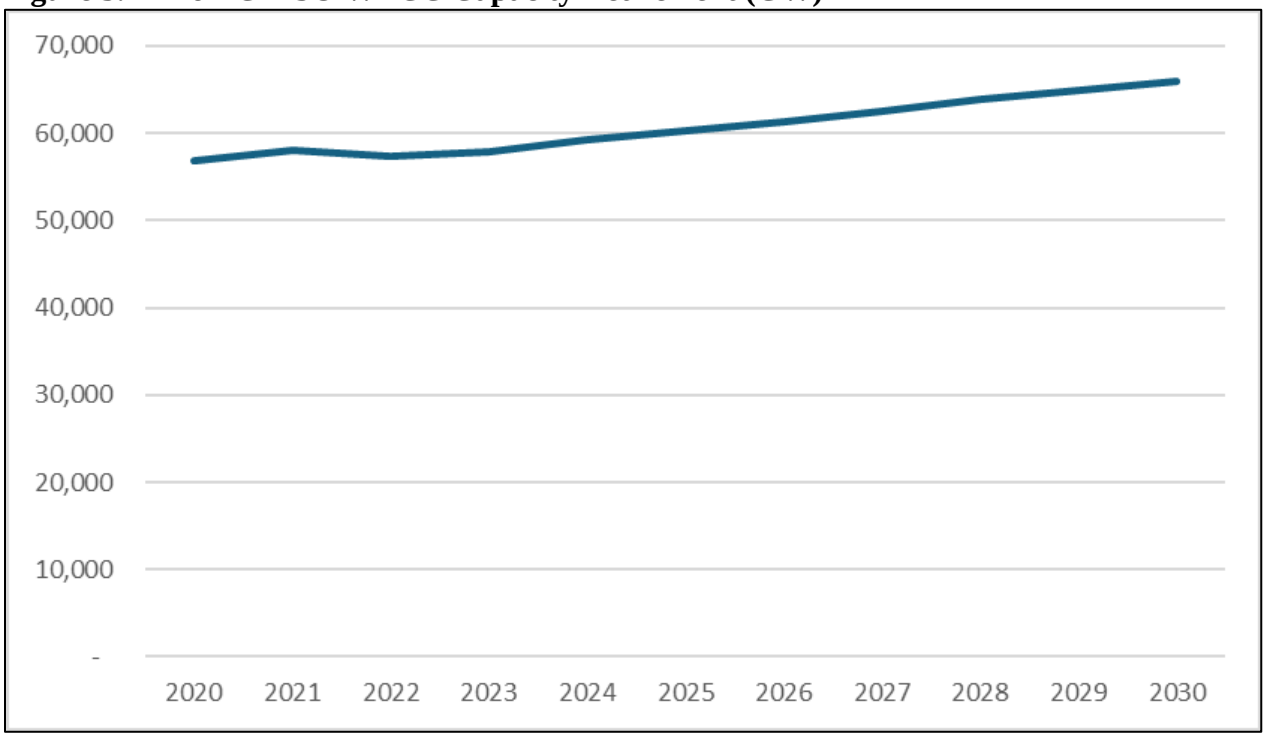
**Emissions and Environment**

Cool weather and low natural gas prices in 2023 led to decreased emissions and low demand for allowances. In addition, the finalization of the Good Neighbor Plan in March 2023 contributed to an 18% NOx emission reduction within the ten implemented states. On April 25, 2024, the U.S. Environmental Protection Agency (EPA) unveiled its final rule to regulate greenhouse gas (GHG) emissions from power plants under Section 111 of the Clean Air Act. The updated rule mandates that coal-fired baseload units achieve 90% carbon capture and storage (CCS) by 2032. It also provides an option for plants scheduled for retirement by 2039 to co-fire up to 40% natural gas as a transitional measure to reduce emissions.

**Non-CAISO WECC Demand Forecast**

After years of relatively stagnant demand nationwide, recent additions of loads—such as data centers, manufacturing facilities, and electrification initiatives—have caused load forecast projections to surge. According to regional outlooks, the non-CAISO WECC region is anticipated to experience a compound annual growth rate (CAGR) of 1.8% from 2024 to 2030. Recent Integrated Resource Plans (IRPs) from utilities across the region, including Nevada Energy, Arizona Public Service, show higher-than-usual load growth expectations, largely due to significant new load additions expected to come online in the coming years.

**Figure 3.7 - Non-CAISO WECC Capacity Retirement (GW)**




*Source: Siemens PTI*

**Forward Influence of the IRA**

In August 2022, the US Congress Passed the Inflation Reduction Act ("IRA"). The notable near-term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits or investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative attempt to avoid losing production tax credits.

As of November 2024, the future of some provisions of the IRA remains uncertain under the new administration. While a repeal of the IRA is unlikely as that would require congressional approval, the Trump administration could slow the payment of grants and loans or rescind or modify regulations and guidance issued to date on how to implement provisions of the IRA. This action would make it difficult for companies and individuals to plan with certainty with respect to claiming tax credits for investments in new renewable and non-emitting technologies including EVs and offshore wind. A US policy movement away from federal climate initiatives could also enhance China's global dominance in clean energy industries such as solar panels and EVs, while potential new import tariffs could hinder the deployment of energy generation and other technologies supported by the IRA.

## Natural Gas Prices

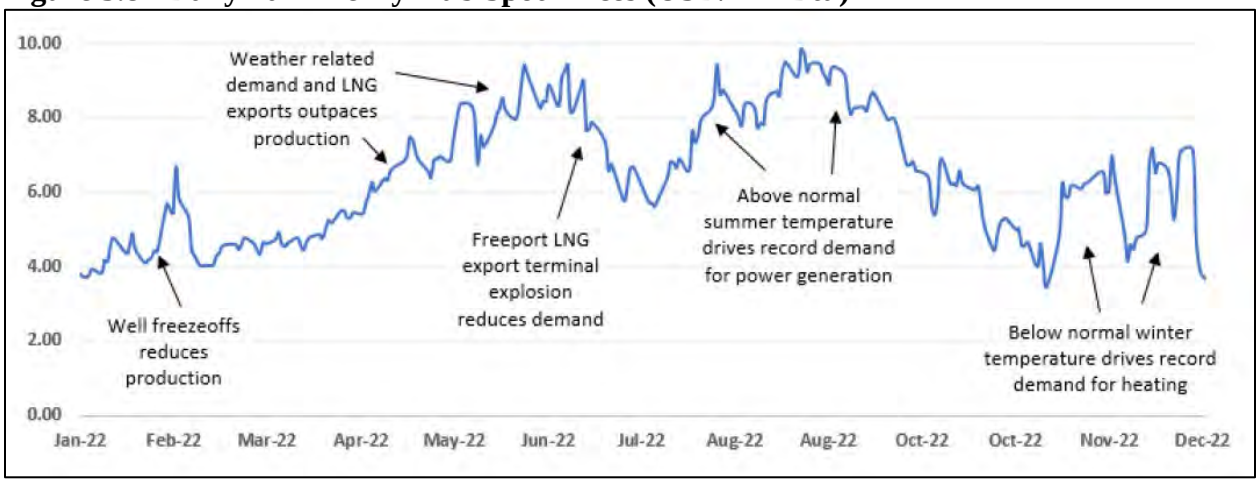
**2022 Summary**

In the first quarter of 2022, demand for natural gas surpassed production in the US due to well freeze-offs in January and February. High withdrawals of natural gas from storage during this time

caused prices to increase. Continued demand for U.S. liquified natural gas (LNG) exports into Europe due to Russia's war on Ukraine, as well as increasing weather-driven demand, caused upward price pressure.

In the second quarter, starting in May, weather-related demand for natural gas for electric generation as well as uncertainty around storage injections led to an increase in natural gas prices. The Henry Hub spot prices, as you can see in Figure 3.8, rose to over $9/MMBtu. However, in late June, the second largest LNG export terminal in the US, accounting for 17% of total LNG export capacity, suffered a tragic explosion which took it offline. As such prices fell to below $6/MMBtu. For the first half of 2022, the U.S. was the largest exporter of LNG in the world, and over two-thirds of the cargoes headed to Europe.

**Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)**




*Source: S&P Global, Siemens PTI*

The price of natural gas quickly rebounded in July and August, because of a heat wave in many parts of The U.S., which resulted in record high demand for power generation. The Western States of the U.S. were particularly affected by this not only due to higher demand for power but also from reduced supply of hydro resources due to continuing drought.

Despite these challenges, US Lower 48 supply surpassed pre-pandemic levels in the first half of 2022, led by gas production growth as higher prices spurred increased rig activity. Rig activity was more pronounced in low-cost basins such as Permian (Texas/New Mexico) and Haynesville (Louisiana) as they have better infrastructure to access demand areas.

Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

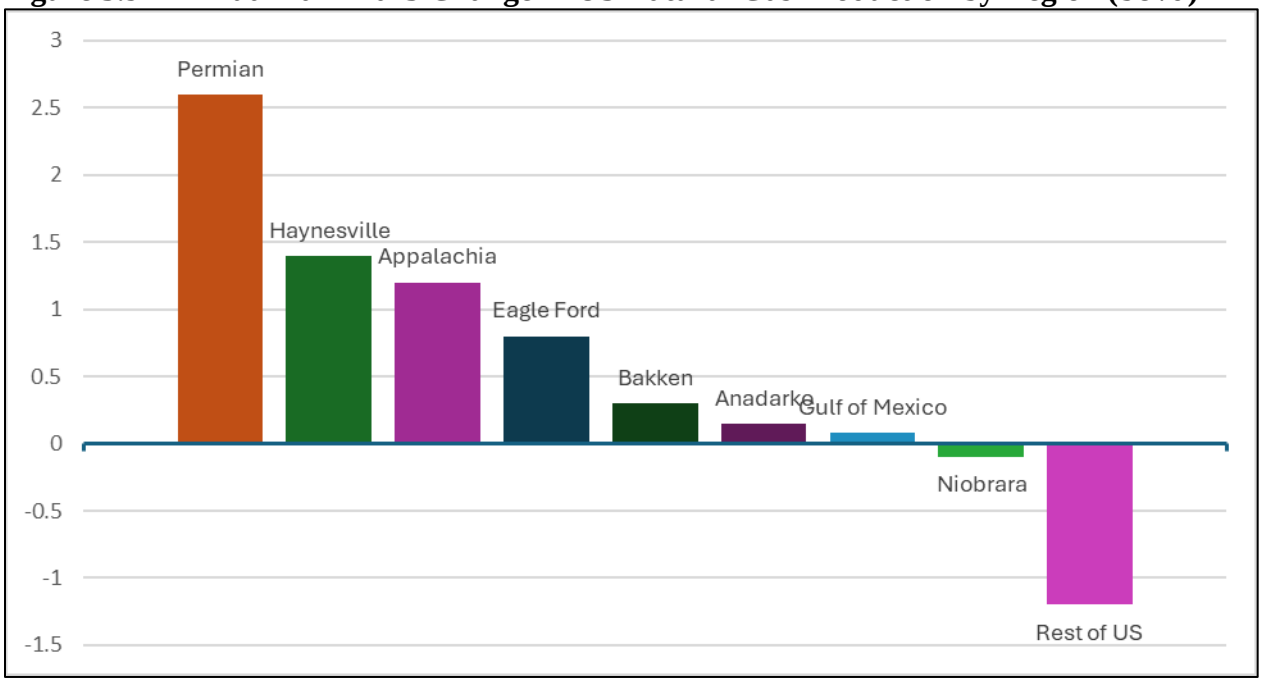
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

demand for natural gas. This higher demand, the constraint on pipelines, and reduce storage levels contributed to significantly higher prices that the west is currently experiencing.

**2023 Summary**

In 2023, U.S. natural gas prices saw a significant drop compared to the previous year, with the benchmark Henry Hub price averaging $2.57 per million British thermal units (MMBtu), a steep 62% decline from 2022. This price decline was largely driven by record-high production levels, which reached an average of 104 billion cubic feet per day (Bcf/d), 4% higher than the previous year. This production increase was particularly notable in key regions like the Permian, Haynesville, and Appalachia, where technological advancements and strong oil prices supported higher outputs.

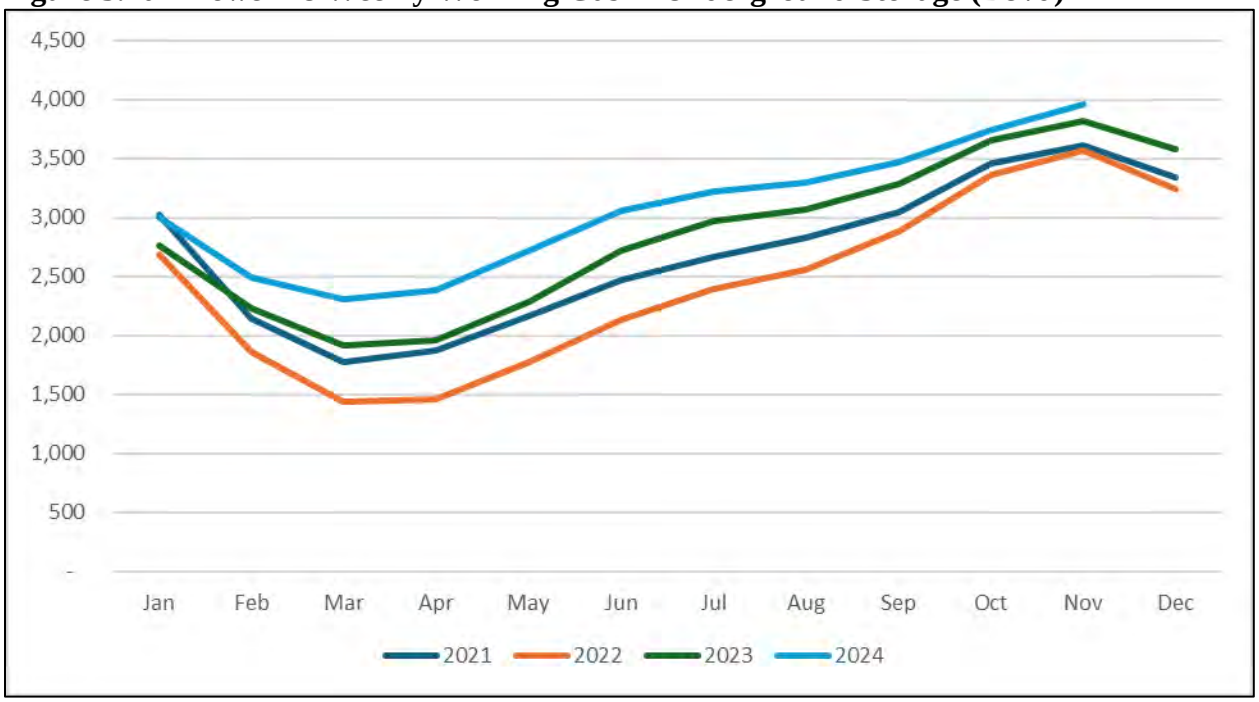
**Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)**




*Source: EIA, Siemens PTI*

Weather played a critical role in shaping the market. Warmer-than-average winter temperatures in January and February significantly reduced demand for natural gas in residential and commercial heating, particularly in the Midwest and Northeast, where natural gas is a primary heating source for most households. These mild conditions led to the lowest winter consumption levels in seven years and kept storage inventories above the five-year average for much of the year, further pressuring prices downward.

**Figure 3.10 – Lower 48 Weekly Working Gas in Underground Storage (Bcf/d)**




*Source: EIA, Siemens PTI*

On the West Coast, natural gas prices were influenced by unique regional factors. Severe winter storms early in the year disrupted supply chains and increased demand for heating in California and surrounding areas, creating temporary price spikes in localized markets. However, as weather conditions stabilized and milder temperatures returned, these pressures eased, and West Coast prices aligned more closely with the broader national trend of declining natural gas costs.

While domestic demand for natural gas remained relatively flat overall, there were notable increases in liquefied natural gas (LNG) exports, which rose by 12%, and pipeline exports, which increased by 9%. These exports helped offset some of the impact of reduced residential and commercial consumption. Despite this, the overall supply-demand balance remained tilted toward oversupply, with storage levels high and production continuing at record rates.

Adding to the dynamics was the gradual recovery of the Freeport LNG facility, which had been offline due to an outage in 2022 and returned to full operation in 2023. While this increased export capacity, it did not significantly alter the broader market trajectory, as domestic production remained the dominant factor. Prices remained under $3.00/MMBtu for most of the year, with May marking the lowest monthly average at $2.19/MMBtu, illustrating how robust supply and subdued demand combined to create one of the least volatile years for natural gas in recent history.

**2024 Summary**

In 2024, U.S. natural gas prices remained relatively low, with the Henry Hub averaging under $3.00 per MMBtu through November. Production levels, while slightly reduced compared to the previous year, remained robust at an average of 103.3 Bcf/d according to EIA. This marked the first annual production decline since 2020, driven by lower drilling activity because of subdued spot prices. Despite this, overall supply continued to outpace domestic demand, keeping inventories above the five-year average.

In the Permian Basin of western Texas and southeastern New Mexico, natural gas production, primarily as associated gas from oil wells, increased this year alongside rising oil production driven by oil prices, with expanding pipeline takeaway capacity, such as the Matterhorn pipeline, continuing to support higher production levels despite some volatility caused by periodic pipeline maintenance affecting Permian supply

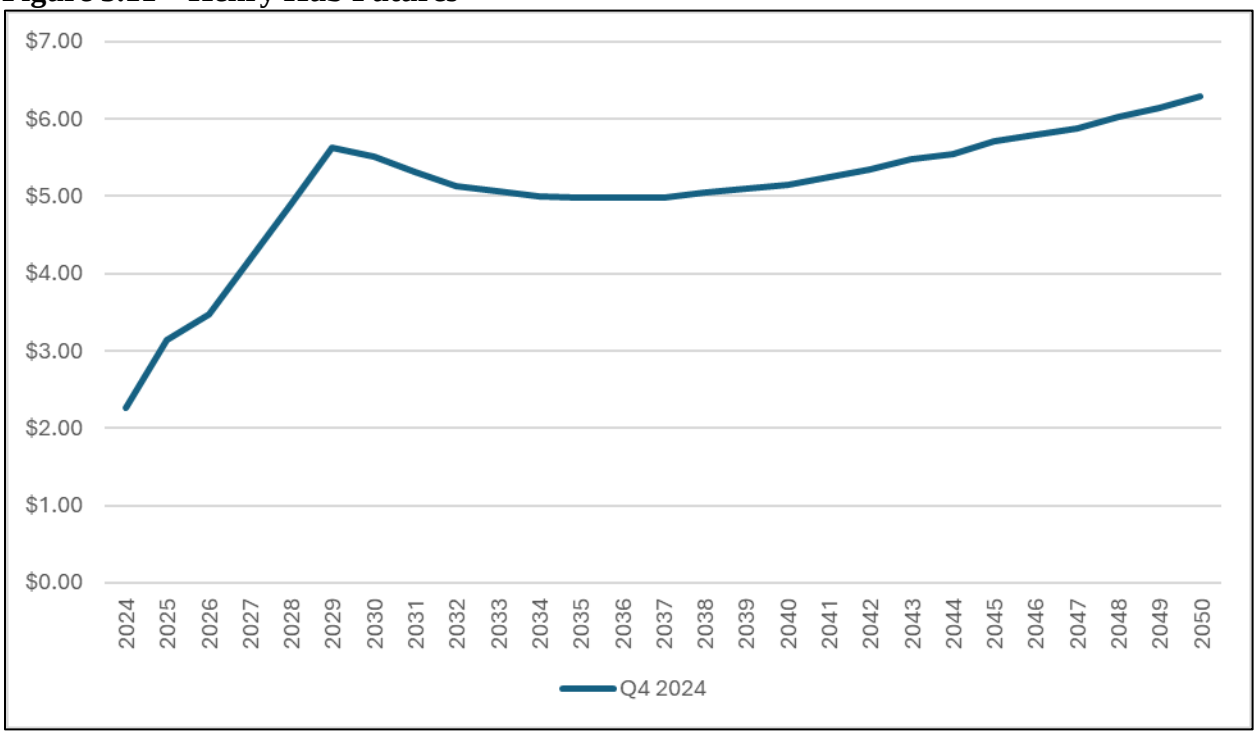
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts to diversify energy sources remained a priority. However, higher exports were offset by stable industrial demand and moderate consumption for power generation, resulting in a balanced domestic market. Regional pricing saw temporary variations, particularly in the West, where localized weather events, including early-season storms, increased heating demand briefly. Despite these regional factors, the national market reflected a stable supply-demand balance with minimal volatility. This relative stability was further supported by the continued high storage levels, maintaining downward pressure on prices throughout the year.

**2025-2032 Forward View**

As we consider the 2025 to 2030 timeframe, our fundamental forecast for natural gas spot prices at Henry Hub indicates a steady upward trend, with prices expected to average in the mid-$4/MMBtu range in real terms by 2027. Total natural gas demand is projected to reach 122 Bcf/d by 2029, a 13% increase from 2023 levels, driven primarily by rising LNG exports and pipeline deliveries to Mexico. LNG exports are anticipated to double by 2027, as several terminals reach final investment decisions and expand capacity. Similarly, pipeline exports to Mexico are expected to grow significantly, fueled by increased demand for power generation and industrial use.

To meet this growing demand, U.S. natural gas production is expected to expand significantly, particularly from low-cost basins such as the Permian, Eagle Ford, and Haynesville. These regions are well-positioned to serve both domestic and export markets, benefiting from their proximity to demand centers and the development of new takeaway capacity through ongoing pipeline expansion projects. While the market may experience tightness through the middle of the decade due to accelerating LNG export growth, the combination of increased production and strategic infrastructure investments is expected to stabilize supply and support a balanced market by 2032.

**Figure 3.11 – Henry Hub Futures**




*Source: Siemens PTI, GPCM*

**Conclusion**

In summary, the natural gas market is poised for significant growth through the 2025–2030 timeframe, driven by surging export demand and supported by robust production from key basins and expanding infrastructure. While domestic demand shifts modestly, the market's stability will hinge on the alignment of production growth with expanding export capacity. Despite periods of tightness mid-decade, strategic investments and rising supply will position the market for long-term equilibrium, with Henry Hub prices reflecting this balance.

## PacifiCorp's Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to over 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative multi-state process (MSP) has been used to develop an allocation methodology. This collaborative process has led to the development and adoption of PacifiCorp's current inter-jurisdictional cost-allocation method.

The underlying principle of each of the historical inter-jurisdictional cost-allocation methods has been the use of PacifiCorp's system as a single whole. Except for distribution, all states are served from a common portfolio of generation and transmission assets, which enables the company to leverage economies of scale and take advantage of load diversity to plan and operate in a way that results in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the

costs and benefits of coal-fired generation while other states are not. Similarly, diverging state polices related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol had been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system.

In 2024, PacifiCorp determined that a negotiated agreement was unlikely given the differences in state energy policies and data limitations for parties to compare alternatives. PacifiCorp will file a new allocation methodology for approval by all six state commissions in 2025 for implementation in 2026 and beyond. PacifiCorp's guiding principles in the development of the new allocation methodology will continue to be:

1. Provide a long-term, durable solution
2. Follow cost-causation principles
3. Minimize rate impacts at implementation
4. Allow for state autonomy for new resource portfolio selection
5. Maintain and optimize system-wide benefits and joint dispatch to the extent possible
6. Enable compliance with state policies
7. Ensure credit-supportive financial outcome
8. Provide the company with a reasonable opportunity to recover its costs

## Environmental Regulation

The upcoming administration change featuring Republican control of the House, Senate, and presidency, sets the stage for significant shifts in federal energy policy that could influence PacifiCorp's portfolio selection process used in the development of future IRPs. PacifiCorp recognizes the potential for new legislative and regulatory priorities to impact the energy sector and resource planning. The company actively monitors federal legislative and regulatory developments and participates in rulemaking processes by submitting comments, engaging in hearings, and providing policy assessments to ensure alignment with evolving requirements.

Suggested upcoming legislative priorities under the new administration include changes to the Inflation Reduction Act and a reconciliation bill with energy as a focal point that could directly impact PacifiCorp's existing and potential generation portfolio.

# Federal Policy Update

## National Electric Vehicle Infrastructure Formula Program

*$5 billion FY 2022-2026*

The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

- The acquisition, installation, and network connection of EV charging stations to facilitate data collection, access, and reliability
- Proper operation and maintenance of EV charging stations
- Long-term EV charging station data sharing

On February 6, 2025, the FHWA released a letter suspending approval of state electric vehicle infrastructure deployment plans pending review of the policies underlying the implementation of the NEVI Formula Program. The FHWA aims to have updated draft NEVI Formula Guidance published for public comment in the spring. After the public comment period has closed, FHWA will publish updated final NEVI Formula Guidance that responds to the comments received.

## Section 11401 Grants for Charging and Fueling Infrastructure

*$2.5 billion for FY 2022 – 2026*

Competitive grant program to strategically deploy publicly accessible electric vehicle charging infrastructure and other alternative fueling infrastructure along designated alternative fuel corridors. At least 50 percent of this funding must be used for a community grant program where priority is given to projects that expand access to EV charging and alternative fueling infrastructure within rural areas, low- and moderate-income neighborhoods, and communities with a low ratio of private parking spaces. Opportunity to obtain funding through this grant closed on September 11, 2024.

## New Credits and Considerations for Non-emitting Resources – Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation signed into law in August 2022 by President Biden. Substantive details of how the legislation will be implemented are still being fleshed out in the form or regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand, such as tax credits for electric vehicles.

Features of the IRA include:

- The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting

economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.

- Key Energy Provisions:
  - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
  - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
  - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2025 IRP, resources in designated areas are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

## New Credits and Considerations for Customer Resources–Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income.

Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a $3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

The IRA also extends the federal Investment Tax Credit (ITC) for small scale solar systems through 2034 and expands the credit to include standalone energy storage systems as well. Since the passage of the IRA, the ITC has been extended beyond its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC is set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of $0.50–5.00 per square foot (/sf) of floor area to owners of new and

improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than $25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, IRA increases the credit to 30% of cost, with an annual cap of $1,200 along with smaller limits for most items, but it also allows up to $2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of $500).

## New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in April 2024, EPA finalized new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units (Clean Air Act Section 111(d) rule).

For new combustion turbines, the final rule establishes three subcategories based on operating intensity as measured by capacity factor.

1. Base load turbines (operating above 40% of maximum annual capacity factor) must initially meet a standard reflective of an efficient combined cycle design and achieve 90% carbon capture by January 1, 2032.
2. Intermediate load turbines (operating between 20% and 40% of capacity factor) must meet a standard reflective of an efficient simple cycle design.
3. Low load turbines (operating below 20% capacity factor) must meet a standard based on using low-emitting fuels.

For existing coal-fired electric generating units (EGUs), the final rule subcategorizes plants based on the units intended operational timeline.

1. Long-term units (operating beyond January 1, 2039) must meet emission limits based on 90% carbon capture and storage (CCS) by January 1, 2032.
2. Medium-term units (retiring by January 1, 2039) must meet limits by January 1, 2030, using 40% natural gas co-firing.
3. Near-term units (closing before January 1, 2032) have no emission reduction obligations.

For existing gas- or oil-fueled steam units, the final rule subcategories units based on capacity factor.

1. Base load units (annual capacity factor greater than or equal to 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,400 lb/MWh)
2. Intermediate load units (annual capacity factor between 8% and 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,600 lb/MWh)
3. Low load units (annual capacity factor less than 8%) must meet a standard based on using low-emitting fuels.

States are required to submit implementation plans within two years of the rule's publication. These plans must show meaningful engagement with stakeholders, including affected communities and reliability authorities. States also have flexibility to consider factors like Remaining Useful Life, allow for emissions trading and averaging, and provide one-year compliance extensions for delays beyond an operator's control.

The rule has been challenged by multiple parties and is currently awaiting a decision from the D.C. Circuit Court of Appeals.

## Credit for Carbon Oxide Sequestration – Internal Revenue Service § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[7] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[8] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024, to January 1, 2026.

The Inflation Reduction Act made considerable changes to the 45Q tax credit in 2022. The tax credit amount increased to $60/tonne (use) and $85/tonne (storage), the construction window was extended to January 1, 2033, the minimum capture thresholds were lowered (18,750 tonnes per year for electric generating facilities) and the Act now requires 75% of a generating units $CO_2$ production to be captured, among other requirements.

## Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NOX), particulate matter (PM), and sulfur dioxide ($SO_2$). The primary standards are set at a level that protects public health with an adequate margin of safety. The secondary standards are set to protect the public welfare from adverse effects including those related to effects on soils, water, crops, vegetation, anthropogenic materials, among other impacts. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan (SIP) to bring that area into compliance, and that plan must be approved by

[7] Before February 9, 2018, the tax credit was strictly for $CO_2$.
[8] The tax credit reaches $35/tonne and $50/tonne in 2026.

EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

**Ozone NAAQS**

In October 2015, EPA issued a final rule modifying both the primary and secondary 8-hour ozone from 75 parts per billion (ppb) to 70 ppb. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its "Good Neighbor Rule" for the 2015 ozone NAAQS (the "Ozone Transport Rule" or "OTR"), which proposed a federal implementation plan (FIP) to eliminate interstate transport of ozone precursors from states that EPA identified as significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The proposed rule covered 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and California. Specifically, EPA proposed in that action to implement emissions reductions by requiring some sources within these states to participate in revised provisions of the Cross-State Air Pollution Rule (CSAPR). EPA applied the interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NOx emissions from electric generating unit (EGU) sources within the borders of 25 states during the ozone season and to limit ozone season NOx emissions from non-EGU sources in 23 states to reduce interstate ozone transport.

On February 13, 2023, EPA finalized disapproval of interstate ozone transport SIP submissions for the 2015 8-hour ozone NAAQS for multiple states and issued a partial disapproval for two additional states. This included the SIP for Wyoming. In the same action, EPA deferred final action on its proposed disapproval for Wyoming. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a 1% threshold instead of the one ppb threshold despite EPA previously recognizing, in an August 2018 memorandum, that state may establish an alternative contribution threshold of 1 ppb. States, like Utah, for which EPA issued disapproval actions of their interstate ozone transport SIPs were required to comply with the interstate ozone transport FIP for the 2015 ozone standard upon finalization of that action on March 2023. Due to EPA's delayed final action on Wyoming's SIP submission, Wyoming was not required to comply with the final interstate ozone transport FIP for the 2015 8-hour ozone NAAQS.

Numerous states and industries, including PacifiCorp, challenged certain provisions of the ozone interstate transport SIP disapprovals and FIP for the 2015 ozone standard. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA's denial of the Utah SIP with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the interstate transport FIP for the 2015 ozone NAAQS while the stay remains in place. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been stayed.

The EPA finalized approval of Wyoming's interstate ozone transport SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the interstate ozone transport FIP. Given the court stay of EPA's disapproval of Utah's SIP, PacifiCorp

was not subject to the interstate ozone FIP requirements for the 2015 ozone NAAQS during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication on the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of the litigation.

In addition to litigation over SIP disapprovals, numerous appeals of, and motions to stay, the interstate ozone FIP were filed in four different circuit courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the interstate ozone transport FIP for the 2015 ozone standard that was filed by several state and industry parties. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the interstate ozone transport FIP with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement, and other industries affected by the rule, filed supportive requests for a stay on the same day. The U.S. Supreme Court granted a stay of the FIP on June 27, 2024. Accordingly, states are not required to comply with the ozone transport FIP pending the stay.

On December 9, 2024, EPA signed a final rule to reclassify the Northern Wasatch front, which includes Salt Lake County, from moderate to serious nonattainment for the 2015 Ozone NAAQS. PacifiCorp's Gadsby facility is in the Northern Wasatch Front area and was previously identified as a major source subject to Utah's moderate nonattainment area SIP for Ozone. In anticipation of EPA's decision, the Utah Department of Environmental Quality (DEQ) requested that PacifiCorp submit a reasonably available control technology (RACT) analysis to the Utah DEQ's Division of Air Quality. PacifiCorp submitted the RACT analysis on January 9, 2024, and followed the top down RACT analysis process for each nitrogen oxide and volatile organic carbon emission source at the at the Gadsby plant. Plant emissions from 2017 were utilized to prepare cost effectiveness analyses for add-on controls; these analyses demonstrated that no additional controls are cost effective at this time.

**Particulate Matter NAAQS**

On October 17, 2006, EPA revised the level of the 24-hour $PM_{2.5}$ NAAQS from 65 micrograms per cubic ($\mu g/m^3$) meter to 35 $\mu g/m^3$. On May 10, 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ nonattainment areas from moderate to serious for the 2006 24-hour $PM_{2.5}$ NAAQS. PacifiCorp's Lake Side and Gadsby facilities were subject to major source requirements due to their emissions of PM2.5. On April 27, 2017, PacifiCorp submitted a Best Available Control Technology (BACT) determination for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices for the Lake Side and Gadsby facilities in the SIP.

On November 17, 2020, EPA finalized redesignation of the Salt Lake City and Provo nonattainment areas to attainment for the 2006 24-hour $PM_{2.5}$ NAAQS. On April 6, 2021, EPA reopened the comment period after adding supplemental information to the proposal. Re-designation to attainment would have no effect on current emissions and operating limits for the Lake Side and Gadsby facilities.

On March 6, 2024, EPA revised the primary annual $PM_{2.5}$ NAAQS from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$. EPA has not yet designated areas as attainment, nonattainment, unclassifiable/attainment, or unclassifiable under this new standard.

## Regional Haze

Clean Air Act (CAA) Section 169A includes a program for protecting visibility in the nation's mandatory Class I Federal areas, which include national parks and wilderness areas. The CAA directs EPA to promulgate regulations to assure reasonable progress toward meeting the goal of protecting visibility. In 1990, CAA section 169B was added to further address visibility impairment, specifically, impairment from regional haze. EPA promulgated the Regional Haze Rule in 1999, which requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado, and Montana). The states are required to update their regional haze rule plans generally every ten years, with second planning period revisions due in August of 2023. Litigation over the first planning period requirements for both Utah and Wyoming are mostly concluded.

On July 6, 2005, EPA published final amendments to its regional haze rule to require emission controls known as Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include PM, NOx, $SO_2$, certain VOCs, and ammonia. The 2005 amendments included BART guidelines for states to use in determining which facilities must install controls and presumptive controls for certain sources subject to BART. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities.

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the regional haze program. EPA issued additional guidance on July 8, 2021, that discusses source selection, characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, consideration of visibility in making control determinations, and the consideration of five additional factors, among other topics.

### Utah Regional Haze

In May 2011, the state of Utah submitted to EPA a regional haze SIP for the first planning period requiring the installation of $SO_2$, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the $SO_2$ portion of the Utah regional haze SIP and disapproved the NOx and PM portions for Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's approval of the $SO_2$ SIP was appealed by environmental groups to the Tenth Circuit. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the SIP on the basis that the NOx and PM BART determinations for the sources did not comply with the Regional Haze rules. PacifiCorp and the state's appeals were dismissed as was the appeal filed by environmental groups in the Tenth Circuit. In June 2015, Utah submitted a revised SIP to EPA for approval which included an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2 and crediting NOx emission reductions from Hunter Units 1, 2, and 3 and Huntington Units 1 and 2. On July 5, 2016, EPA published a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a FIP. The FIP established NOx emission limitations on Hunter Units 1 and 2 and Huntington Units 1 and 2 that are reflective of Selective Catalytic Reduction (SCR) and Low-NOx Burners (LNB) and Separated Overfire Air (SOFA). On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative

and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP as well as the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the court.

Utah and PacifiCorp worked with EPA to develop a revised Utah regional haze SIP, based on new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA that would require reporting of all deviations from compliance with the applicable requirements under BART and the BART Alternative, including the emission limits for Hunter and Huntington.

On January 22, 2020, EPA published its proposed approval of the Utah SIP revision and withdrawal of the FIP requirements that would have required emissions limitations for the Hunter and Huntington plants equivalent to SCR plus upgraded combustion controls (LNB/SOFA). EPA subsequently finalized approval of the SIP and withdrawal of the FIP as proposed on November 27, 2020. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp and EPA's motion to dismiss the Utah regional haze petitions.

Environmental groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to EPA's approval of Utah's regional haze SIP for the first planning period. After holding the case in abeyance at EPA's request, the Tenth Circuit lifted the abeyance and granted PacifiCorp and Hunter co-owners and Utah's pending motions to intervene. On August 14, 2023, the Tenth Circuit determined EPA properly approved the Utah regional haze SIP for the first planning period and denied environmental groups' petition.

On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the state as part of its second planning period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and $SO_2$ at the Hunter and Huntington units to meet second planning period requirements.

The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022, and submitted the SIP to EPA on August 2, 2022. The SIP differs from PacifiCorp's Reasonable Progress Analysis and requires updated mass-based NOx limits. The SIP also concluded that existing $SO_2$ limits in Hunter and Huntington's title V permits were necessary to make reasonable progress but required no further $SO_2$ emission limits for the plants.

On December 2, 2024, EPA finalized a final partial approval and partial disapproval for Utah's regional haze state implementation plan for the second planning period without simultaneously

finalizing a federal implementation plan. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management (FLM) consultation components of the SIP. EPA's disapproval of Utah's long-term strategy is based, in part, on EPA's rejection of Utah's finding that installation of SCR or other physical NOx pollution controls for Hunter and Huntington is not necessary to achieve reasonable progress. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously finalized FIP. PacifiCorp filed a petition for reconsideration on EPA's disapproval action on January 30, 2025, and filed a petition for review in the Tenth Circuit the next day.

**Wyoming Regional Haze**

On January 30, 2014, EPA published a final rule partially approving and partially disapproving the Wyoming regional haze SIP for the first planning period and promulgating a FIP to address the deficiencies EPA found in the Wyoming SIP submission. As a result of the 2014 final rule and FIP, the following controls were required at PacifiCorp facilities for the regional haze first planning period:

- Naughton Units 1 and 2: LNB/OFA, with an emission limit of 0.28 lbs/MMBtu for each unit
- Naughton Unit 3 by December 31, 2014: SCR + LNB/SOFA, 0.07 lb/MMBtu (30-day rolling average).
- Jim Bridger Unit 3 by December 31, 2015: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 4 by December 31, 2016: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 2 by December 31, 2021: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 4, 2015
- Jim Bridger Unit 1 by December 31, 2022: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 3, 2015
- Dave Johnston Unit 3: Either a commitment to retire by 2027 and LNB/OFA, with an emission limit of 0.28 lbs/ MMBtu (30-day rolling average) or SCR + LNB/OFA, with an emission limit of 0.07 lbs/ MMBtu (30-day rolling average)
  Wyodak Unit 1: SCR+ LNB/SOFA, with an emission limit of 0.07 lb/ MMBtu (30-day rolling average)

Naughton – In its 2014 rule, EPA approved Wyoming's determination that NOx BART for Units 1 and 2 was LNB and OFA. While EPA approved Wyoming's NOx BART determination of SCR and LNB/OFA, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) for Naughton Unit 3, EPA stated that it would approve limitations that reflect the conversion of Unit 3 to natural gas once Wyoming submitted the requisite SIP revision. On November 28, 2017, Wyoming submitted to EPA a source-specific revision to its regional haze SIP for the first planning period for the Naughton Unit 3 conversion. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed Unit 3 to operate on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approving Wyoming's SIP revision for Naughton Unit 3's gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as NOx BART for Units 1 and 2 in the Tenth Circuit. On August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied

environmental groups' petition.

Jim Bridger – In its 2014 rule, EPA approved Wyoming's determination that Jim Bridger Units 1 and 2 meet an emission limit of 0.07 lb/MMBtu (30-day rolling average) by 2022 and 2021, respectively. EPA also approved Wyoming's NOx BART determination that required Jim Bridger Units 1 and 2 to meet a NOx emission limit of 0.26 lb/MMBtu (30-day rolling average) by March 4, 2019. For Jim Bridger Units 3 and 4, EPA approved Wyoming's determination that the appropriate level of $NO_X$ control for Units 3 and 4 for purposes of reasonable progress is the SCR-based emission limit in the SIP of 0.07 lb/MMBtu, with compliance dates of December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. Accordingly, SCR was installed on Jim Bridger Units 3 and 4 by the dates required by the Wyoming SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an air permit application for monthly average plant-wide NOx and $SO_2$ emission limits, in addition to an annual combined NOx and $SO_2$ limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. PacifiCorp proposed that the plantwide limits were more cost effective while leading to better modeled visibility than SCR installations on Units 1 and 2. Wyoming submitted a regional haze SIP revision to the EPA on May 14, 2020, that incorporated PacifiCorp's proposed emission limits in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2. While EPA communicated that it would issue a proposed approval of Wyoming's Jim Bridger SIP, the proposal was not issued before the administration change in 2021.

When EPA failed to issue a determination by the statutory deadline in November 2021, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, using authority granted by the Clean Air Act, suspending the existing SIP requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for four months due to the EPA's failure to act on the SIP revision submitted by Wyoming in 2020. EPA published a proposed disapproval of the Jim Bridger SIP revision on January 18, 2022. However, PacifiCorp negotiated a consent decree with Wyoming and an administrative consent order with EPA and the disapproval was not finalized. Under the Wyoming consent decree and EPA administrative consent order, PacifiCorp is required to comply with a compliance plan that allows continued operation of Jim Bridger Units 1 and 2 under the emission limits established by Wyoming in 2020 until they are converted to natural gas in 2024. The consent decree committed Wyoming to processing a SIP revision requiring the conversion and imposing post-conversion emission limits.

On December 30, 2022, Wyoming submitted to EPA for approval a revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming issued to PacifiCorp an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. PacifiCorp completed the conversion. On April 10, 2024, EPA proposed to approve Wyoming's December 2022 SIP revision for Jim Bridger Units 1 and 2. The SIP includes enforceable emissions and heat input limits at Jim Bridger Units 1 and 2, consistent with the conversion of those units to natural gas. EPA accepted comments on the proposed approval through May 10, 2024, but has not yet finalized the approval.

Dave Johnston – EPA's January 20, 2014, FIP action required either the installation of SCR on Dave Johnston Unit 3 or that the unit retire by the end of 2027. PacifiCorp opted not to install SCR. EPA approved Wyoming's NOx BART determination for Dave Johnston Unit 4 of an emission limit of 0.15 lb/MMBtu (30-day rolling average). EPA also approved Wyoming's NOx

reasonable progress determinations for Dave Johnston Units 1 and 2 that no controls were necessary.

Wyodak – EPA's January 20, 2014, FIP action determined SCR + LNB/SOFA to be NOx BACT. PacifiCorp and Wyoming petitioned EPA's FIP that would require SCR at Wyodak in the Tenth Circuit. On September 9, 2014, the Tenth Circuit stayed the NOx emission limits for Wyodak Unit 1 in the regional haze FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. EPA, Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. On January 4, 2021, EPA published the proposed settlement agreement in the Federal Register, requesting public comment. PacifiCorp submitted comments to EPA on March 5, 2021, in support of the Wyodak proposed settlement agreement. However, EPA did not proceed with final approval of the proposed settlement agreement but rather re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit. Litigation for the Wyodak case challenging EPA's denial of the Wyoming SIP and finalization of a FIP recommenced when the mediation process was not successful. On August 15, 2023, the Tenth Circuit found EPA's disapproval of Wyoming's SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act.

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. Wyoming incorporated the four-factor analyses in its SIP for the regional haze second planning period. Wyoming determined that emission limits and planned unit retirements met the reasonable progress goals for Regional Haze. Wyoming submitted the state's regional haze SIP for the second planning period to EPA on August 10, 2022.

On December 2, 2024, EPA finalized partial approval and partial disapproval of Wyoming's regional haze SIP for the second planning period. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA's disapproval of Wyoming's long-term strategy is based in part on the state's decision to forego a full four-factor analysis for units at Jim Bridger, Naughton, Dave Johnston, and Wyodak. There are no new compliance obligations for PacifiCorp at this time, as the disapproval action did not include a simultaneously finalized FIP. On January 30, 2025, the state of Wyoming submitted an "open letter" to EPA stating its concerns about the agency's disapproval of the regional haze second planning period plan for the state. On January 31, 2025, the state also filed a petition for review in the Tenth Circuit. PacifiCorp filed a petition for reconsideration with the agency on January 30, 2025, and petition for review in the Tenth Circuit the next day.

**Colorado Regional Haze**

Craig- The Colorado regional haze SIP for the first planning period established $SO_2$ BART emission limits on Craig Units 1 and 2 of 0.11 lb/MMBtu (30-day rolling average). Colorado incorporated NOx emission limits of 0.28 lb/MMBtu (30-day rolling average) for Craig Unit 1 and 0.08 lb/MMBtu (30-day rolling average) for Craig Unit 2 in the SIP. Although the state determined that SNCR was reasonable for BART for both Units 1 and 2, Tri-State and Colorado agreed to a NOx emission control plan for Unit 2 that reflected SCR and was therefore more stringent than the BART determination. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) at Craig Units 1 and 2, which could be met through the operation of the existing fabric filter baghouses.

Hayden- In its regional haze SIP for the first planning period, Colorado determined that the $SO_2$ BART emission limit for Hayden Unit 1 is 0.13 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.13 lb/MMBtu (30-day rolling average). These limits are met with the operation of the existing controls. For NOx, Colorado determined that the $NO_X$ BART emission limit for Hayden Unit 1 is 0.08 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.07 lb/MMBtu (30-day rolling average). These BART emission limits could be met through the installation and operation of SCR. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) for Hayden Unit 1 and Unit 2. These PM emission limits can be met through the operation of the current fabric filter baghouses.

EPA found Colorado's determinations for the Craig and Hayden units to be approvable and finalized approval of the Colorado regional haze SIP for the first planning period on December 31, 2012. Environmental groups appealed EPA's action in February 2013, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment, with a NOx BART emission limit for Craig Unit 1 is 0.07 lb/MMBtu, calculated on a 30 boiler-operating-day rolling average at Craig Unit 1 by August 31, 2021, 2021.

On May 26, 2017, Colorado submitted a SIP amendment to EPA that reflected further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements The revised SIP required Craig Unit 1 to meet an annual $NO_X$ emission limit of 4,065 tons per year by December 31, 2019. The SIP revision also required the unit to either convert to natural gas by August 31, 2023, and if converting to natural gas, comply with a $NO_X$ emission limit of 0.07 lb/MMBtu (30-day rolling average) beginning August 31, 2021, or shut down by December 31, 2025. EPA approved the SIP on July 5, 2018.

Colorado Regional Haze Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units 1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA on March 22, 2021. However, EPA has not yet acted on the Colorado regional haze SIP for the second planning period. The Colorado SIP is part of the deadline suit filed by environmental groups in the federal D.C. District Court.

## Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that coal- and oil-fired facilities achieve emission standards for mercury, acid gas hazardous air pollutants (HAPs), non-mercury HAP metals, and organic HAPs. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, in response to a Supreme Court decision requiring consideration of costs, EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate coal- and oil-fired EGUs under the Clean Air Act.

On February 7, 2019, EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate HAPs, reversing the Agency's

prior determination. On May 22, 2020, EPA published a reconsideration of its 2016 supplemental finding. In the reconsideration action, EPA determined that it is not appropriate and necessary to regulate HAP emissions from coal- and oil-fired EGUs. The rule was effective May 22, 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting EPA's decision to rescind the appropriate and necessary finding. The court granted EPA's motion to hold the cases in abeyance while the agency reviewed the 2020 repeal. On March 6, 2023, EPA finalized a rule rescinding the 2020 revocation of the appropriate and necessary finding. The rule therefore reinstated the finding. Because PacifiCorp plants are in compliance with the MATS standards, the reinstatement of the finding has immediate impact on PacifiCorp's operations.

On April 25, 2024, EPA finalized revisions to the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The final rule, effective July 8, 2024, tightens the standard for emissions of mercury from existing lignite-fired units by 70 percent and sets a more stringent standard for emissions of filterable particulate matter from existing coal-fired power plants. The rule also requires that continuous emissions monitoring be used to demonstrate compliance with the filterable PM standard.

## Coal Combustion Residuals

On April 17, 2015, EPA finalized a rule to regulate the management and disposal of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The rule establishes minimum nationwide standards for new and existing CCR landfills and surface impoundments as well as all lateral expansions consistent of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, recordkeeping, notification, and internet posting requirements. In addition to other requirements, the rule requires existing unlined CCR surface impoundment that is contaminating groundwater to stop receiving CCR and either retrofit or close, except in limited circumstances. The rule also requires the closure of certain landfills and CCR impoundments. The first of these reports was posted to PacifiCorp's CCR compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR and hence are not subject to the final rule.

On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions in the 2015 CCR rule which would have allowed inactive CCR surface impoundment units that had closed by a certain date to forgo groundwater monitoring or other requirements. In response to this decision, EPA published a direct final rule on August 5, 2016, to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under RCRA.

On July 30, 2018, in response to further legal challenge, EPA finalized a rule to establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by EPA. The rule also revised groundwater protection standards for certain constituents. In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, EPA extended the deadline by which facilities must

cease the placement of waste in CCR units closing for cause in certain instances. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule").

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") on August 28, 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which unlined surface impoundments that failed aquifer location restriction must initiate closure. In addition, the rule revised the alternative closure provisions to grant facilities additional time to develop alternative capacity to manage both CCR and/or non-CCR wastewater streams before they must stop receiving waste and initiate closure of their surface impoundments. Finally, the rule revised certain requirements related to the annual groundwater monitoring and corrective action report and the requirements for publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 was placed into service. EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

On November 12, 2020, EPA published the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process that allows facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. EPA proposed these options as part of a subsequent proposal on March 3, 2020. On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program in accordance with the requirements of the Water Infrastructure Improvements for the Nation (WIIN) Act. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 15, 2017, EPA published a request for comment on its proposed permitting guidance which describes EPA’s interpretation of the WIIN Act provisions and how EPA will review states' CCR permit programs The state of Utah adopted the federal final rule in September 2016 and issued the final permit for Huntington Power Plant CCR Landfill on March 21, 2023, and for Hunter Power Plant CCR Landfill on May 15, 2024. It is anticipated that Utah will submit an application to EPA for approval, but the timing of the submission remains uncertain. EPA rejected Wyoming’s application due to concerns about the state’s ability to meet federal standards for the safe management of coal ash.

On May 8, 2024, EPA finalized the legacy surface impoundments rule to (1) extend federal CCR regulatory requirements to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land (CCR management units or CCRMUs) and (2) allow for alternative closure provisions that allow a facility to complete the closure by removal in two stages. The final rule, which became effective on November 8, 2024, includes exemptions and establishes new categories

where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. Affected facilities must conduct a facility evaluation and report to determine the presence of CCRMUs and/or legacy surface impoundments. The first phase of such a report is due February 2026. Because the facility evaluation and report requirement will determine the magnitude of compliance obligations, PacifiCorp cannot assess the full impacts of the rule at this time.

On August 5, 2024, Utah, Wyoming and other Republican-led states filed a petition for review in the D.C. Circuit on EPA's May 2024 legacy rule, arguing that EPA acted arbitrarily and beyond its authority when enacting the new rule. On February 3, 2025, these same petitioners as well as power companies, utilities and trade groups filed their opening brief in a consolidated case contesting the rule in the D.C. Circuit.

## Water Quality Standards

### Cooling Water Intake Structures

The federal Water Pollution Control Act (Clean Water Act) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to, and withdrawals from, waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact." In August 2014, EPA published a final rule, effective October 2014, under section 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule establishes requirements that apply to existing power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from Waters of the United States (WOTUS) and use at least 25 percent of the withdrawn water exclusively for cooling purposes. The rule includes standards to address impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility). The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from WOTUS for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million, but less than 125 million, gallons of water per day.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards. Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs.

### Effluent Limit Guidelines

In November 2015, EPA published final effluent limitation guidelines and standards (ELG) for the steam electric power generating sector which, among other things, regulate the discharge of bottom

ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System (NPDES) permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018, and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with EPA. EPA granted the request for reconsideration and extended certain compliance dates for FGD wastewater and bottom ash transport water limits until November 1, 2020. On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing FGD wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on FGD wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet FGD wastewater requirements and includes additional subcategories to both wastewater categories.

On May 9, 2024, EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule), which includes a new subcategory for EGUs permanently ceasing coal combustion by 2034. The 2024 ELG Rule also imposes a zero liquid discharge requirement at coal-based generating units for bottom ash transport water, flue gas desulfurization wastewater, and coal combustion residual leachate. The rule also eliminates 2020 ELG Rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The rule maintains, however, the 2020 ELG Rule subcategory for EGUs permanently ceasing the combustion of coal by 2028 and oil-fired and small (50 megawatts (MW) or less) EGUs established in the 2015 rule. The rule finalizes additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

Most of the issues raised by the 2024 ELG Rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. In October 2021, the Dave Johnston plant submitted a notice of planned participation in subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream. The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

## Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys,

monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands or that receive federal funding are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects (TB Flats, Ekola Flats, and Cedar Springs) constructed as part of PacifiCorp's Energy Vision 2020 initiative, for example, were required to obtain permits from the State of Wyoming's Industrial Siting Division, which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

## State Policy Update

### California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. CARB's 2022 Scoping Plan was

adopted laying out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279, passed in 2022.

CARB adopted the Advanced Clean Cars II Rule in August of 2022. The rulemaking establishes that by 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded several times since its inception. In September 2018, Governor Brown signed into law Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045. The California Energy Commission, California Public Utilities Commission, and California Air Resources Board have not introduced rules on if and how electric utilities will demonstrate compliance with SB 100. Interim targets for the carbon-free target were subsequently adopted by SB 1020 in 2022.

## Idaho

In 2007, Idaho released its State Energy Plan, focusing on developing of a broad range of power generation options, improving energy efficiency, diversifying the state's energy portfolio, and reducing dependency on fossil fuels. The plan outlined strategies for energy conservation, the development of renewable energy sources, and improvements to transmission infrastructure within the state, aiming to balance growth with environmental stewardship and promote both economic development and sustainable energy practices.

In 2012, Idaho updated its 2007 plan to address new energy challenges and opportunities, emphasizing five core objectives: 1) a secure and stable energy system for Idaho's citizens and businesses, 2) maintaining Idaho's low-cost energy supply, 3) protecting public health and conserving natural resources, 4) promoting economic growth, job creation, and rural economic development, and 5) ensuring Idaho's energy policy can adapt to changing circumstances.

In October of 2020, Governor Brad Little issued Executive Order 2020-17, continuing the role of the Office of Energy and Mineral Resources (OEMR) as the central coordinator for Idaho's energy policy. The OEMR manages energy production, conservation, and policy alignment, ensuring the state's energy resources remain stable and cost-effective.

## Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of

Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

In 2007, Oregon enacted Senate Bill (SB) 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged as follows: 27 percent for 2025-2029, 35 percent for 2030-2034, 45 percent for 2035-2039, and 50 percent for 2040 and every subsequent year thereafter. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp filed its first Clean Energy Plan (CEP) on May 31, 2023, which included possible pathways towards compliance with HB 2021 emissions reduction goals, inclusive of the Small-Scale Renewable (SSR) targets and with emphasis on community-based actions. As also directed by HB 2021, PacifiCorp convened a Community Benefits and Impacts Advisory Group in the fall of 2022. An Oregon Tribal Nations Clean Energy-specific engagement series was started in March of 2023 after six months of direct outreach. The engagement series was formatted by informed feedback from outreach to Oregon Tribal Nations members with whom PacifiCorp had an existing relationship, and through new Tribal Nations relationship building.

In December 2022, Oregon Department of Environmental Quality adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. In Jan of 2022, HB 2165 passed requiring that all electricity companies (with ≥25,000 retail customers) recover the cost of prudent infrastructure investments in transportation electrification. Furthermore, in November 2021, Oregon adopted California's emission standards for HMDV via

the Advanced Clean Truck Rules 2021, paving the way for Oregon to adopt a target of 100% of new MHDV sales being ZEVs by 2050.

## Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020 and every year thereafter. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In 2019, the Washington Legislature passed the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its retail electricity sales be supplied from renewable and non-emitting resources by 2045. PacifiCorp submitted its inaugural Clean Energy Implementation Plan (CEIP) on December 30, 2023, establishing a trajectory towards CETA compliance both for the current CEIP period, 2022 – 2025, and across the next two decades.

In 2021, Washington Legislature passed the Climate Commitment Act, which establishes a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with serving Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

- Improving the efficiency of their fuel production processes
- Producing and/or blending low-carbon biofuels into the fuel they sell
- Purchasing credits generated by low-carbon fuel providers, including electric vehicle charging providers

## Utah[9]

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, which allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, which enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved the Electric Vehicle Infrastructure Program on December 20, 2021, for implementation on January 1, 2022. The program construct will undergo regulatory review every three years through 2032.

In March 2024, the Utah Legislature passed SB 224, Energy Independence Amendments, that modifies the factors the Public Service Commission must consider when evaluating certain proposed energy resource decisions, establishes parameters for an affected electrical utility's recovery of costs associated with proven dispatchable generation resources located within the state, and encourages the commission to evaluate the purchase of excess proven dispatchable generation capacity.

In March 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, which requires the Public Service Commission to act in accordance with the state energy policy and make certain determinations before authorizing the early retirement of an electrical generation facility.

## Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility;

[9] Significant Utah legislative activity gathered interest in the 2025 IRP public input meeting series and stakeholder feedback. Regarding Utah SB-224, see Appendix M, stakeholder feedback form #13 (Emma Verhamme). Portfolio planning is currently not directly impacted by Utah SB-224, however variant and sensitivity studies may reflect this potential, such as the Low-Cost Renewables case and the No Coal 2032 case. Additional discussion of Utah activity is addressed in Appendix M, stakeholder feedback form #37 (Utah Citizens Advocating Renewable Energy).

requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. During the 2024 legislative session the Reliable and Dispatchable Low-Carbon Energy Standard statute was amended through SF 42, which extended the deadline for compliance with the Low-Carbon Energy Standards from July 1, 2030, to July 1, 2033.

In 2024, the Wyoming legislature passed SF 0023 Public Utilities-Energy Resource Procurement (SF 23) and SF 0024 Public Service Commission-Integrated Resource Plans (SF 24). SF 23 requires public utilities to conduct a solicitation process that is approved by the Wyoming Public Service Commission to acquire or construct a significant energy resource after July 1, 2024. A significant energy resource consists of 100 megawatts or more of new utility-owned generating capacity or utility-contracted generating capacity that has a dependable life or contract term of 10 or more years. SF 24 requires the Wyoming Public Service Commission to engage in long-range planning regarding public utility regulatory policy to facilitate the well-planned development and conservation of utility resources and requires the Commission to adopt rules providing a process for the review and acknowledgement of an action plan within an IRP.

## Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb $CO_2$/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. Effective February 2025, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 876 lb GHG/MWh.

PacifiCorp purchased Chehalis in 2008 and this change in ownership is the act that triggered the applicability of the standard. Because the EPS was 1,100 lb GHG/MWh during the time of triggered applicability, that is the standard that Chehalis complies with. It isn't until Chehalis undergoes a change in ownership, upgrade, or new or renewed long-term financial commitment with anyone other than Bonneville Power Administration that applicability to the lowered standard would be triggered.

## Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.3, with additional discussion below.

**Table 3.3 – State RPS Requirements**

| | California | Oregon | Washington | Utah |
|---|---|---|---|---|
| Legislation | • Senate Bill 1078 (2002)<br>• Assembly Bill 200 (2005)<br>• Senate Bill 107 (2006)<br>• Senate Bill 2 First Extraordinary Session (2011)<br>• Senate Bill 350 (2015)<br>• Senate Bill 100 (2018) | • Senate Bill 838 Oregon Renewable Energy Act (2007)<br>• House Bill 3039 (2009)<br>• House Bill 1547-B (2016) | • Initiative Measure No. 937 (2006)<br>• SB 5400 (2013) | • Senate Bill 202 (2008) |
| Requirement or Goal | • 20% by December 31, 2013<br>• 25% by December 31, 2016<br>• 33% by December 31, 2020<br>• 44% by December 31, 2024<br>• 52% by December 31, 2027<br>• 60% by December 31, 2030 and beyond<br>• Planning target of 100% renewable and zero-carbon by 2045<br>* Based on the retail load for a three-year compliance period | • 5% by December 31, 2011<br>• 15% by December 31, 2015<br>• 20% by December 31, 2020<br>• 27% by December 31, 2025<br>• 35% by December 31, 2030<br>• 45% by December 31, 2035<br>• 50% by December 31, 2040<br>* Based on the retail load for that year | • 3% by January 1, 2012<br>• 9% by January 1, 2016<br>• 15% by January 1, 2020 and beyond<br>* Annual targets are based on the average of the utility's load for the previous two years | • Goal of 20% by 2025 (must be cost effective)<br>• Annual targets are based on the adjusted[10] retail sales for the calendar year 36 months before the target year |

## California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[11] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[12] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.4 below.

[10] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.
[11] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[12] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

**Table 3.4 – California Compliance Period Requirements**

| Compliance Period | Procurement Quantity Requirement Calculation |
|---|---|
| Compliance Period 1 (2011-2013) | (20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales) |
| Compliance Period 2 (2014-2016) | (21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales) |
| Compliance Period 3 (2017-2020) | (27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales) |
| Compliance Period 4 (2021-2024) | (35.75% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.25% * 2023 Retail Sales) + (44% * 2024 Retail Sales) |
| Compliance Period 5 (2025-2027) | (46.67% * 2025 Retail Sales) + (49.33% * 2026 Retail Sales) + (52% * 2027 Retail Sales) |
| Compliance Period 6 (2028-2030) | (54.67% * 2028 Retail Sales) + (57.33% * 2029 Retail Sales) + (60% * 2030 Retail Sales) |

SB 2 (1X) established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or
>
> Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[13]

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.5.

[13] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.

**Table 3.5 – California Balanced Portfolio Requirements**

| California RPS Compliance Period | Balanced Portfolio Requirement |
|---|---|
| Compliance Period 1 (2011-2013) | Category 1 – Minimum of 50% of Requirement<br>Category 3 – Maximum of 25% of Requirement |
| Compliance Period 2 (2014-2016) | Category 1 – Minimum of 65% of Requirement<br>Category 3 – Maximum of 15% of Requirement |
| Compliance Period 3 (2017-2020)<br>Compliance Period 4 (2021-2024)<br>Compliance Period 5 (2025-2027)<br>Compliance Period 6 (2028-2030) | Category 1 – Minimum of 75% of Requirement<br>Category 3 – Maximum of 10% of Requirement |

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC, and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources, or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites. Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

## Oregon

In June of 2007, Oregon established a comprehensive renewable energy policy, including RPS, with the passage of SB 838, the Oregon Renewable Energy Act. [14] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[15] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are set at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.

[14] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[15] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[16]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

PacifiCorp files an annual RPS compliance report by June 1 of every year. In addition, after the passage of Oregon House Bill 3161, effective January 1, 2024, ORS 469A.075 now aligns the filing of a renewable plan (formally called the Renewable Portfolio Implementation Plan or RPIP) with the filing of the IRP. Please see Appendix R for detailed information on PacifiCorp's 2025

[16] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

RPS Renewable Plan, including annual targets, list of resources, applicable requirements, and assumptions and methodologies. These RPS compliance reports and plans are available on PacifiCorp's website.[17]

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

## Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative, later codified in Utah Code Title 54 Chapter 17.[18] This law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 29, 2023. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.0 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

[17] www.pacificpower.net/ORrps
[18] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

## Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[19] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[20]

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

## REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states. One exception to REC sales is a special contract for one industrial customer where the customer foregoes REC sales revenue in exchange for a REC retirement to maintain renewable claims for corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming.

[19] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[20] www.pacificpower.net/report

# Clean Energy Standards

## Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act (CETA). Under the law, Washington utilities are required to be carbon neutral by January 1, 2030, and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030, and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric sales over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

## Oregon

As noted under State Policy Updates, above, in July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

## California

In 2018, California passed Senate Bill 100 – known as the "100 percent Clean Energy Act of 2018," which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state's Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California's electricity is renewable.

In 2022, California passed Senate Bill 1020, the Clean Energy, Jobs, and Affordability Act of 2022. This bill established interim targets to the previously established SB 100. It requires that eligible renewable energy resources and zero-carbon resources supply:

- 90% of all retail sales of electricity to California end-use customers by December 31, 2035
- 95% of all retail sales of electricity to California end-use customers by December 31, 2040
- 100% of all retail sales of electricity to California end-use customers by December 31, 2045
- 100% of electricity procured to serve all state agencies by December 31, 2030

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. In February 2025, the Commission adopted final rules that exempted multijurisdictional electric companies with 60,000 or fewer customers in California from compliance with the hourly reporting requirement.

## Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The Company requested an extension and filed the final plan on March 29, 2024 that included a proposal to: conduct additional technical and economic analyses for an Allam Fetvedt Cycle Project at either the Dave Johnston or Wyodak facilities by conducting a pre-FEED study in conjunction with SK and 8 Rivers; conduct additional technical and economic analyses by conducting a front-end engineering and design (FEED) study at the Jim Bridger facility; and no determination of a low-carbon portfolio standard at this time since CCUS continues to be evaluated for its technical and economic feasibility. The Commission approved the Company's final plan in public deliberations held on September 19, 2024. The statute also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

## Transportation Electrification

The electric transportation market continues to strengthen since 2022. Overall, light duty battery electric vehicle sales have grown since 2022 resulting in a market share of about 9% in the United States[21]. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind[22]. By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales[23]. EV sales still comprise a small portion of overall sales, however this will shift as medium-duty/heavy-duty (MD/HD) customers continue to expand. PacifiCorp also hosts major interstates and traffic corridors that will see continued electrification through policies discussed above. Furthermore, many businesses are moving to electrify their fleets from port authorities, transit agencies, etc. which will increase load over time.

This rapidly evolving market represents a potential driver of future load growth, and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation could improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (MD/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV

[21] October 2024 auto sales volume to hold steady in the US | S&P Global
[22] Electric vehicle market and policy developments in U.S. states, 2023 - International Council on Clean Transportation
[23] Electric Vehicle Sales and the Charging Infrastructure Required Through 2035

forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop commercial and residential charging programs, research new rate designs and implement time-of-use pricing programs and managed charging pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities.

In California, Pacific Power's Electric Vehicle Infrastructure Rule 24 will pay for and coordinate the design and deployment of service extensions from our electrical distribution line facilities to the service delivery point for separately metered electric vehicle charging stations.[24] Pacific Power continues to provide programs funded by the Oregon Clean Fuels program as well as the recent HB 2165 legislation passed that created a transportation electrification benefits charge to support infrastructure development in the state of Oregon. As of November 2022, the Washington Utility and Transportation Commission approved Pacific Power's Transportation Electrification Plan which sets out an estimated spend of $3.5 million over the next five years to support TE in Washington state.

In Utah, PacifiCorp is implementing the $50 million Electric Vehicle Infrastructure Program that has four core components: Company-owned public fast chargers, customer incentives, innovative projects, and outreach and education efforts. In June 2024, the first four locations with Company-owned public direct current fast chargers (DCFC) became operational. It is anticipated that there will be roughly 20 locations with an estimated 100 DCFC stations throughout Utah by the end of the program. As of the end of 2023, PacifiCorp had supported installation of over 4,800 EV ports throughout the territory.

Electric vehicle load is reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles.

## Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation

[24] California Electric Vehicle Infrastructure Line Extensions (pacificpower.net)

does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

As of December 31, 2024, PacifiCorp has 15 FERC licensed hydroelectric projects. Each license may contain a single or multiple hydro developments (e.g., dams and powerhouses). PacifiCorp is currently seeking new licenses for the Cutler (30 MW) and Ashton (7.85 MW) hydroelectric projects. A new license for Cutler is expected in 2025, and a new license for Ashton in 2027. The next project to undergo the FERC relicensing process is the Bear River hydroelectric project (77 MW). That project's FERC license expires in 2033.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Tribal and interested party consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies could place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad involvement or that incorporate measures agreed upon through multi- party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

## Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2023, PacifiCorp had incurred approximately $33 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on

PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing implementation and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

### Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 7.

### PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting Tribal, agency and others' interests through creative solutions, is the best way to achieve environmental and social improvements while balancing customer costs and risks. PacifiCorp also has reached agreements to decommission projects where that has been the most cost-effective outcome for customers.

## Rate Design

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No 20-035-04 The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has several rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

### Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings All other remaining costs are recovered through volumetric- based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-

day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of December 2023, less than one percent of customers have opted to participate in the time-of-day rate option.

As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

### Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers an optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage,

### Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

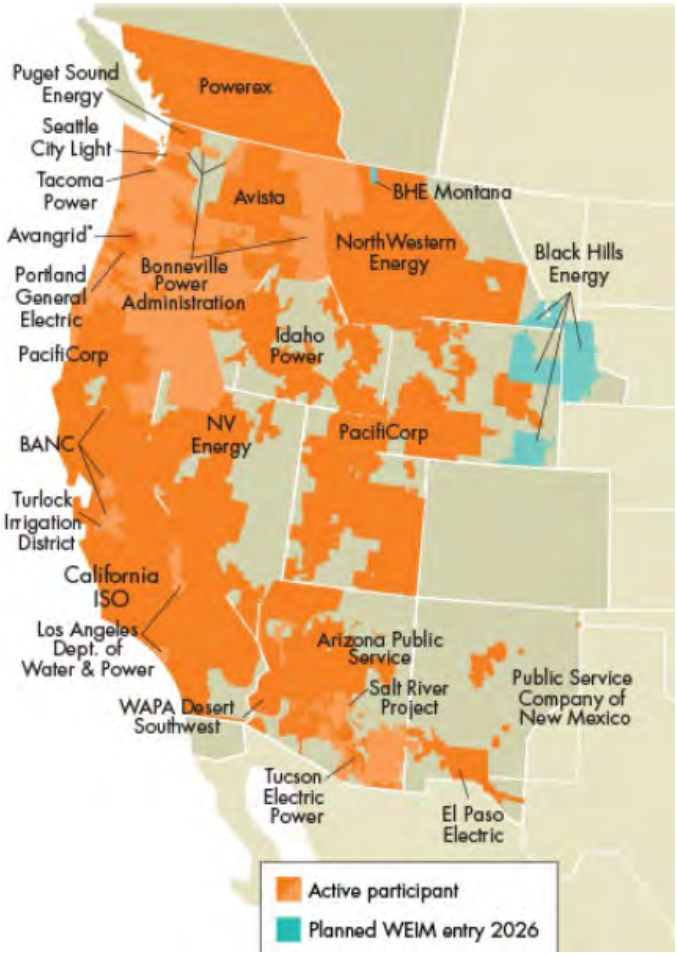
## Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service

(APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. El Paso Electric (EPE), Western Area Power Administration Desert Southwest (WAPA DSW) and Avangrid (AVR) entered in April 2023. In 2026, Black Hills Montana and Berkshire Hathaway Energy Montana (BHE Montana) have planned entry into the WEIM.

The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Texas, New Mexico, Utah, Washington, Wyoming, and British Columbia which make up almost eighty percent of the Western Energy Coordinating Council (WECC) load and will expand to include Montana in 2026. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

**Figure 3.12 – Western Energy Imbalance Market Expansion**



The WEIM has produced approximately $5.85B in monetary benefits since inception for participating utilities, quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every fifteen and five minutes within and across the WEIM footprint based on the most economical solution; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexible reserves in all WEIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the WEIM footprint.

A significant contributor to WEIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations that exist in states with a price on carbon (i.e., California and Washington). Generally, transfer quantities are based on transmission and interchange rights between participating balancing authority areas.

After development and expansion of the WEIM in the west, a natural next question was – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of WEIM but short of a full regional transmission organization? PacifiCorp believes the answer is 'yes'.

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023 and received FERC approval on December 28, 2023. EDAM is scheduled to go live on May 1, 2026, and to date, PacifiCorp and Portland General Electric have signed their EDAM implementation agreements.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint as stakeholders who want to participate in Markets+ would need to exit WEIM. In addition to a smaller WEIM footprint, day-ahead markets with different design elements and requirements for participation exacerbate the seams issue which already exist throughout the west. SPP and stakeholders filed their tariff with FERC on March 29, 2024, and received a deficiency letter on July 31, 2024, that SPP is currently working through to remedy FERC's clarification and additional information request due at the end of November 2024. SPP does not believe the SPP Markets+ timeline will be impacted for their projected spring 2027 go-live target and stakeholders must be vigilant to ensure the markets work as cohesively as possible.

## Recent Resource Procurement Activities

PacifiCorp's past procurement efforts have resulted in a number of contracts for new resources that have recently come online or are projected to come online through 2026 as summarized in Table 3.6.[25] These resources are also included in the resource tables presented in Chapter 6.

[25] See Appendix M, stakeholder feedback form #59 (Renewable Northwest)

**Table 3.6 – PacifiCorp's Recent and Upcoming New Resource Additions**

| Resource | Type | Resource Capacity (MW) | Storage Capacity (MW) | Year contracted | Commercial operation | Source |
|---|---|---|---|---|---|---|
| Appaloosa Solar | Solar | 200 | n/a | 2020 | Jan 2024 | Customer program: UT Sch 34 |
| Rocket Solar | Solar | 80 | n/a | 2020 | Feb 2024 | Customer program: UT Sch 34 |
| Castle Solar | Solar | 40 | n/a | 2020 | Apr 2024 | Customer program: UT Sch 32 |
| Horseshoe Solar | Solar | 75 | n/a | 2020 | Apr 2024 | Customer program: UT Sch 34 |
| Elektron Solar | Solar | 80 | n/a | 2020 | Apr 2024 | Customer program: UT Sch 34 |
| Oregon Institute of Tech. BESS | Battery Storage | n/a | 2 | n/a (owned) | Mar 2025 | OR HB 2193 (2015) |
| Rock River Wind | Wind | 50 | n/a | n/a (owned) | Sep 2024 | Repowering of existing site |
| Cedar Creek Wind | Wind | 151.8 | n/a | 2022 | Mar 2024 | 2020 AS RFP |
| Anticline Wind | Wind | 190 | n/a | 2022 | Dec 2024 | 2020 AS RFP |
| Boswell Wind | Wind | 100.5 | n/a | 2022 | Dec 2024 | 2020 AS RFP |
| Cedar Springs Wind IV | Wind | 320 | n/a | 2022 | Jan 2025 | 2020 AS RFP |
| Rock Creek Wind I | Wind | 350.4 | n/a | n/a (owned) | Dec 2024 | 2020 AS RFP |
| Rock Creek Wind II | Wind | 400 | n/a | n/a (owned) | Sep 2025 | 2020 AS RFP |
| Green River Energy Center | Solar + Battery | 400 | 400 | 2022 | May 2026 | 2020 AS RFP: amended to increase storage capacity in 2023 |
| Faraday Solar and Storage | Solar + Battery | 525 | 150 | 2023 | Sep 2025 | Customer program: UT Sch 34 |
| Hornshadow Solar | Solar | 300 | n/a | 2023 | Jun 2025 | Customer program: OR Sch 272 |
| Dominguez Grid | Battery Storage | n/a | 200 | 2024 | Jun 2026 | Negotiated after 2022 AS RFP |
| Enterprise Storage | Battery Storage | n/a | 80 | 2024 | Jun 2026 | Negotiated after 2022 AS RFP |
| Escalante BESS | Battery Storage | n/a | 80 | 2024 | Jun 2026 | Negotiated after 2022 AS RFP |
| Granite Mountain BESS East | Battery Storage | n/a | 80 | 2024 | Jun 2026 | Negotiated after 2022 AS RFP |
| Iron Springs BESS | Battery Storage | n/a | 80 | 2024 | Jun 2026 | Negotiated after 2022 AS RFP |
| Oregon Comm. Solar (aggregate) | Solar | 38.8 | n/a | various | various | Oregon Community Solar Program |
| **Total** | | **3,301** | **1,072** | | | |

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.7 summarizes recent RFP activities.

**Table 3.7 – PacifiCorp's Requests for Proposal Activity**

| RFP | RFP Objective | Status | Issued | Completed |
|---|---|---|---|---|
| Renewable energy credits (Purchase) | Excess system RECs | Ongoing | Based on specific need | Ongoing |
| Renewable energy credits (Purchase) | California compliance needs | Ongoing | Based on specific need | Ongoing |
| Short-term Market (Sales) | System balancing | Ongoing | Based on specific need | Ongoing |
| 2024 Utah Renewables Community RFP | Seeking resources consistent to the Community Clean Energy Act (Utah Code 54-17-901 to -909) | Ongoing | Expected November 2024 | Expected October 2025 |

## 2022 All-Source RFP

On April 1, 2024, PacifiCorp published the company's 2023 Integrated Resource Plan Update. The 2023 IRP Update preferred portfolio demonstrated that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is material customer benefit to scaling down and delaying resource acquisition until after 2030. As such, the 2022 All-Source Request for Proposals was terminated. PacifiCorp's 2025 IRP will inform the next steps for incremental resource acquisition.

## 2024 Utah Renewables Community RFP

The 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP) is administered by the Community Renewable Energy Agency (Agency) on behalf of customers that participate in the Community Clean Energy Program (Program). The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

## 2025 All-Source RFP

PacifiCorp will seek to file the 2025 All Source RFP ("2025AS RFP") based on results identified in the 2025 IRP preferred portfolio. Further updates on the status and schedule of the 2025AS RFP will be provided as they become available.

**Recent Resource Procurement/DSM Procurement**

In 2023, PacifiCorp issued a Request for Proposals to re-procure program delivery services for the Home Energy Savings and Wattsmart Business energy efficiency programs in Washington and California. As a result of the re-procurement, new contracts for Washington and California were signed in 2024. For Washington specifically, PacifiCorp followed its Competitive Procurement Framework,[26] including seeking Washington DSM Advisory Group input and posting a notice on the Company website prior to releasing the Request for Proposals. In 2024, PacifiCorp issued a Request for Proposals to re-procure program delivery services for Wattsmart Business in Utah, Idaho and Wyoming, and contracting is underway.

In 2024, PacifiCorp also issued an RFP for energy efficiency implementation services for a commercial new construction program in its Utah service area. The procurement and subsequent contracting steps are still underway.

[26] 2022-2023 Biennial Conservation Plan, Appendix 6 (Docket UE-201830)
The current Competitive Procurement Framework for Washington Conservation and Efficiency Resources is available in Appendix 6 to the 2024-2025 Biennial Conservation Plan (Docket UE-230904).

# CHAPTER 4 – TRANSMISSION

## CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2025 IRP preferred portfolio includes the following notable transmission upgrades:[1]
    - A series of upgrades to increase transfer capability between southern Utah and the Wasatch Front, projected to come online between 2026 and 2036.
    - New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington, projected to come online in 2031.
    - 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon, projected to come online in 2032.
    - New transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.
    - A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2), projected to come online in 2036.
- Further, the 2025 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp's transmission system including investment in infrastructure in Oregon, Utah, and Washington that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp's customers.

## Introduction

PacifiCorp's bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

[1] Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP base modeling:

- The Energy Gateway South transmission line - a new 416-mile, high-voltage 500 –kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in Q4-2024.
- The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in Q4-2024.

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, considering scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a carbon free energy future.
4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Resiliency to protect against system and market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

# Regulatory Requirements

## Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which

supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on this data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[2] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

## Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC reliability coordinator. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to always meet aggregate electrical demand for customers. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

[2] For example, PacifiCorp's application to begin the Environmental Impact Statement process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

## Generation Interconnection Study Methodology Changes

In 2022 PacifiCorp filed a request with FERC to modify its large generator interconnection procedure to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions were implemented into generation interconnection studies starting with Cluster 2. The new operating assumptions have allowed PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2023 FERC released Order 2023 which required modifications of all transmission provider's including PacifiCorp's, generator interconnection procedures. Several notable changes were included in Order 2023. First, FERC required all transmission providers to move to a first ready, first serve cluster study process which PacifiCorp had already transitioned to in 2020. Second, FERC required all transmission providers to use a distribution factor analysis to assign cost responsibility to specific interconnection customer requests driving the need for network upgrades. This change to PacifiCorp's procedures will allow for projects sited in locations that have smaller impacts on the transmission system, avoiding cost responsibility for upgrades in the region that its project does not cause. Other aspects of the Order 2023 include requiring 100 percent of site control for proposed generating facilities with the initial application and substantial withdrawal penalties at the facilities study stage both of which should disincentivize speculative projects. PacifiCorp will implement a transition process in which existing interconnection requests that have not yet proceeded far enough in the study process will have the opportunity to be studied in a transition cluster study or be withdrawn. PacifiCorp's next application window for new generation interconnection requests will open in 2026.

## Aeolus to Mona/Clover (Gateway South – Segment F)

The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled to come online by the end of 2024.

## Windstar-Populus (Gateway West – Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

**Figure 4.1 - Segment D**




- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming.
- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020.
- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

## Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

**Figure 4.2 - Segment E**




The Gateway West Segment E project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

## Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The record of decision (ROD) and right-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management (BLM) to review progress.

## Boardman-Hemingway (Segment H)

Boardman-to-Hemingway (B2H) is an approximately 290-mile high-voltage 500-kV transmission line capable of coming online in 2027. PacifiCorp is continuing to coordinate with regional transmission providers and retail customers to evaluate options for this project.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power's 2023 IRP identified the B2H as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2027 or beyond.

The BLM released its record of decision ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the

B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018, for lands administered by the USFS based on the analysis in the final environmental impact statement. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019, in support of construction of a portion of the B2H project on 7.1-miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

On September 27, 2022, Oregon's Energy Facility Siting Council approved the Oregon site certificate completing Oregon's permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, BPA and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville's exit of the project with Idaho Power acquiring Bonneville's share responsibility of the project. This will provide Idaho Power with a 45 percent share of the project and retain PacifiCorp's 55 percent share. Additional terms under negotiations include changes in transmission service between PacifiCorp and BPA, between BPA and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to BPA customers in southeast Idaho via the B2H line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power's transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023.

Idaho Power has applied for Certificates of Public Convenance and Necessity (CPCN) in Oregon and Idaho. Issuance of both certificates were received in June of 2023. PacifiCorp received a CPCN in Idaho in June 2023 and in Wyoming in August 2023.

The current project schedule includes projected completion in 2027.

At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

## Spanish Fork – Mercer 345-kV line

The 2025 preferred portfolio includes the construction of a new, approximately 50-mile, 345-kV transmission line between Spanish Fork Substation and Mercer substation in Utah, with an identified in-service date of 2036, based on projected interconnection requirements. Load-service and reliability requirements may bring this date forward, as could accelerated generator

interconnection demand. PacifiCorp has begun the permitting process for this new transmission line and is currently targeting an in-service date of 2027 for the line.

### Other Transmission System Improvements

The 2025 IRP preferred portfolio also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

## Energy Gateway Transmission Expansion Plan

### Introduction

Given the long–lead time required to successfully site, permit, and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

### Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements and other state-specific policy goals. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

### Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy

groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

- **Rocky Mountain Area Transmission Study**
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion is like Gateway West.
  - Southeast Idaho to southwest Utah expansion akin to Gateway Central, Segment B, Segment C and Sigurd to Red Butte (in service 2015).
  - Improved east-west connectivity like Energy Gateway Segment H alternatives.

> "The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices."

- **Western Governors' Association Transmission Task Force Report**
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high conventional resource scenarios. Again, for PacifiCorp's system, the transmission expansion that supported these scenarios closely resembled Energy Gateway's configuration.

> "The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location."

- **NorthernGrid Regional Transmission Plan Reports**
  In the 2020-2021 NorthernGrid Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study: the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

> "After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

The NorthernGrid 2022-2023 Regional Transmission Plan identified the regional combination consisting of Gateway West (Segment D.3 and Segment E) and B2H as the most efficient and cost-effective set of projects for the NorthernGrid 10-year planning horizon. Gateway South was considered as an in-service project in all cases, including the selected regional combination.

- **WECC/Reliability Assessment Committee (RAC) Annual Reports and Western Interconnection Transmission Path Utilization Studies**
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

> "Path 19 [Bridger] is the most heavily loaded WECC path in the study…. Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

## Energy Gateway Configuration

To address constraints identified on PacifiCorp's transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington. This plan contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was formally a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[3]

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to

[3] http://www.oatioasis.com/ppw/index.html

establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

## Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received more than 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway (B2H) project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing

authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500 kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the B2H Permitting Agreement with Idaho Power Company and BPA that provides for PacifiCorp's participation through the permitting phase of the project. The B2H project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the B2H project, and PacifiCorp continues to support these activities under the conditions of the B2H Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed and placed in service the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In October 2020, Segment D2 of Gateway West, from Aeolus to Jim Bridger was placed into service which included a new 500 kV substation at Aeolus, and a new 345 kV substation at Anticline.

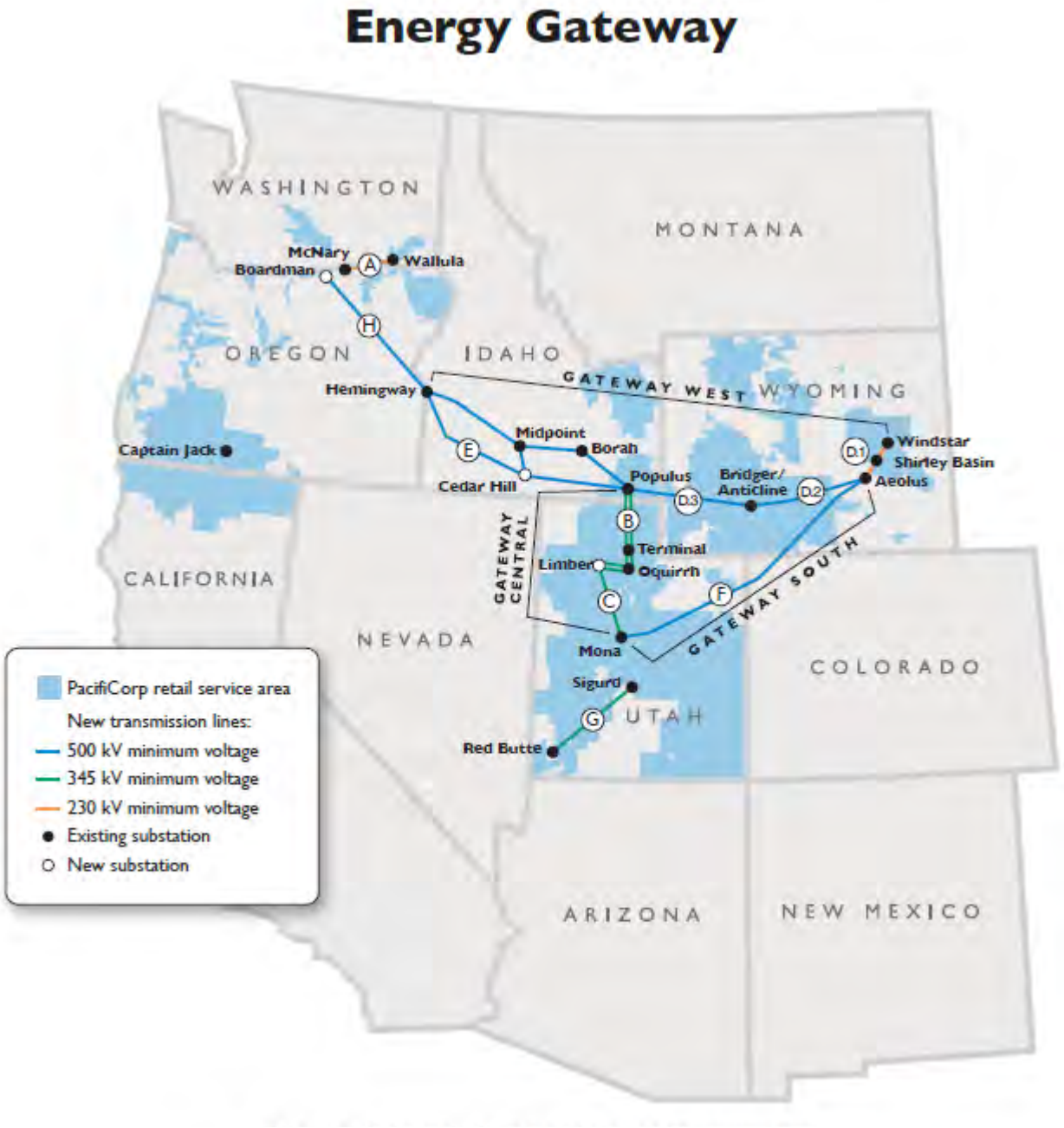
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 230 kV line between Shirley Basin and Dave Johnston substations is under construction with an expected completion date of both lines in December 2024.

Gateway Segment F, referred to as Gateway South, a 416-mile 500 kV line from Aeolus substation in Wyoming to Mona/Clover substation in central Utah is under construction with an expected completion date of December 2024.

Other Gateway segments, including Gateway West Segment D3 from Bridger substation in Wyoming to Populus substation in Idaho and Gateway West Segment E from Populus to Hemingway, in Idaho, are in pre-construction activities to address requirements as defined in their permitting Record of Decision and right-of-way grants issued by the BLM.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

**Figure 4.3 – Energy Gateway Transmission Expansion Plan**




This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

**Table 4.1 – Energy Gateway Transmission Expansion Plan**

| Segment & Name | Description | Approximate Mileage | Status and Scheduled In-Service |
|---|---|---|---|
| (A) Wallula-McNary | 230 kV, single circuit | 30 mi | • Status: completed<br>• Placed in-service: January 2019 |
| (B) Populus-Terminal | 345 kV, double circuit | 135 mi | • Status: completed<br>• Placed in-service: November 2010 |
| (C) Mona-Oquirrh | 500 kV single circuit<br>345 kV double circuit | 100 mi | • Status: completed<br>• Placed in-service: May 2013 |
| Oquirrh-Terminal | 345 kV double circuit | 14 mi | • Status: right-of-way acquisition underway<br>• Scheduled in-service: 2024 |
| (D1) Windstar-Aeolus | New 230 kV single circuit<br>Re-built 230 kV single circuit | 59 mi | • Status: permitting underway<br>• Scheduled in-service: December 2024 |
| (D2) Aeolus-Bridger/Anticline | 500 kV single circuit | 140 mi | • Status: completed<br>• Placed in-service: November 2020 |
| (D3) Bridger/Anticline-Populus | 500 kV single circuit | 200 mi | • Status: permitting underway<br>• Scheduled in-service: 2034 earliest |
| (E) Populus-Hemingway | 500 kV single circuit | 500 mi | • Status: permitting underway<br>• Scheduled in service: 2036 earliest |
| (F) Aeolus-Mona | 500 kV single circuit | 416 mi | • Status: permitting underway<br>• Scheduled in-service: December 2024 |
| (G) Sigurd-Red Butte | 345 kV single circuit | 170 mi | • Status: completed<br>• Placed in-service: May 2015 |
| (H) Boardman-Hemingway | 500 kV single circuit | 290 mi | • Status: pre-construction activities in progress<br>• Scheduled in-service: 2027 |

## Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 20 remedial action schemes (RAS) to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market (EIM) since November 2014. As of April 2023, 22 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system can identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being

developed by the California Independent System Operator (CAISO).[4] While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

## Transmission System Improvements Placed In-Service Since the 2023 IRP

### PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Installs a 345 kV, 200-MVAr switched shunt reactor at Mona substation:
        - Project driver was to address the high voltage conditions experienced during steady state operations under light load and light transfer conditions.
        - Benefits include more effective high voltage control and safe and more reliable power for the Utah area by reducing lines taken out of service and preservation of substation equipment life, particularly circuit breakers which are exposed to frequent switching, reduced probability of mis operation and increased maintenance costs.
2. Northern Utah/Southeast Idaho Area
    - Constructed a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Looped in the existing Populus – Terminal 345 kV line into Bridgerland and Ben Lomond substations:
        - Project driver was to resolve System Operating Limit on Path C.
        - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.
3. Salt Lake City Utah area
    - Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line:
        - Project driver was to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
        - Benefits included mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability.
4. Southern Utah area
    - Reconductor 2.57-miles of the St. George-Purgatory Flat 138 kV transmission line:
        - Project driver was to increase the thermal rating of the line which loaded to 95 percent of its continuous summer thermal rating summer 2022.
        - Benefits included the increases of the transmission line summer continuous rating by 63 MVA.

[4] http://www.caiso.com/Documents/EDAM-Fact-Sheet.pdf

### PacifiCorp West (PACW) Control Area

1. Klamath Falls Oregon Area
    - Constructed a second 230 kV transmission line from Snow Goose to Klamath Falls substation:
        - Project driver was to resolve NERC Standard TPL-001-5 Category P6 (N-1-1) for a double contingencies on the 230-kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
        - Benefits included reinforcing 230 kV system between in Klamath Falls area to cover TPL-001-5 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.
2. Prineville Oregon Area
    - Construct a second 115 kV line between Houston Lake and Ponderosa substations:
        - Project driver was to eliminates potential N-1 overloads of the Prineville 115 kV system associated with increased load, changing generation mix, and grid flow conditions in the area.
        - Benefits included the elimination of a NERC Standard TPL-001-5 Category P1 contingency event for a fault on the 115 kV line between Baldwin Road and Ponderosa substation or a fault on the 115 kV line between Houston Lake and Stearns Butte.

## Planned Transmission System Improvements

### PacifiCorp East (PACE) Control Area

1. Central Utah Area
    - Upgrade the 345-138 kV 167-MVA transformer at Camp Williams substation to a 345-138 kV 700-MVA transformer:
        - Project driver is to correct NERC Standard TPL-001-5 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
        - Benefits include mitigating the NERC Standard TPL-001-5 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability.
    - Install a second 345-138 kV 700 MVA transformer at Oquirrh substation:
        - Project driver is to correct N-1 contingency overload issues in the South Jordan area.

- Benefits include increasing capacity on the 138 kV network serving the Salt Lake Valley.

- Construct a new 345 kV line between Spanish Fork and Mercer 345 kV substations:
  - Project driver is to eliminate the need for the Lakeside II Remedial Action Scheme (RAS) and prevent generation shedding during contingencies. Once flows across the Wasatch Front South boundary exceed 5,562 MW, the Lakeside RAS is no longer effective and cannot be modified to accommodate more flow.
  - Benefits include the increase of path limit to 6,300 MW and allow 1,000 MW additional generation to be interconnected in southern Utah.

2. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers:
   - Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming:
     - Project driver was to correct NERC Standard TPL-001-5 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 12 substations to be addressed as required per R2.8.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-5 Requirement R2.3 deficiencies and as required per R2.8.
3. Salt Lake City, Utah Area:
   - Convert North Salt Lake Substation to 138-kV:
     - Project driver is to correct N-1 contingency overload issues in the North Salt Lake area.
     - Converting to 138 kV at North Salt Lake substation increases the capacity in the area while mitigating the contingency overloads, reduces the burden on the 46 kV system, and brings better reliability to the customers in the area.
   - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard:
     - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
     - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45-MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
   - Construct a new 230-46 kV substation near Eden, Utah:
     - Project driver is to provide a transmission loop to the area to facilitate a line rebuild through Ogden Canyon.
     - Benefits include improved future reliability and area capacity.
4. Southeast Idaho Area:
   - Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation:
     - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.

- Benefits include resolving the NERC Standard TPL-001-5 Category P1 voltage issues.

**PacifiCorp West (PACW) Control Area**

1. Eastern Oregon Area
   - Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers:
     - Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
     - Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.
2. Portland Oregon Area
   - Reconfigure and convert the existing Bonneville Power Administration's (BPA) St. Johns – Columbia and PacifiCorp's (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV:
     - Project driver is to correct NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies for load loss of up to 62-MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
     - Benefits include resolution of NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.
3. Roseburg Oregon Area
   - Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and construct a new 115 kV tie from Roberts Creek to the converted Green substation:
     - Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
     - Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3 percent per year rate.
   - Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer:
     - Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4 percent above nominal in the North Umpqua Hydroelectric System and is nearly 8.7 percent above nominal at Dixonville substation.
     - Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North

Umpqua areas extending the life of the transformers as well as all the downstream equipment.

4. Medford Oregon Area

- Construct a 230-kV transmission line between Lone Pine and Whetstone substations:
  - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230-kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230-kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230-kV line or Dixonville-Grants Pass 230-kV line.
  - Benefits include resolving the NERC Standard TPL-001-5 Category P1 and P6 issues as well as preventing reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
- Construct one new 500-230 kV substation called Sams Valley:
  - Project driver is to correct NERC Standard TPL-001-5 deficiencies for the loss of a single 230 kV line and for N-1-1 and N-2 outages to 230 kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500 kV source to address load growth in the Southern Oregon region.
  - Benefits include adding a second source of 500 kV capacity, adding a new 230-kV line, improving reliability of the 230 kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-5 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

# CHAPTER 5 – RELIABILITY AND RESILIENCY

## CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2025 IRP preferred portfolio includes the Energy Gateway South (GWS) and Energy Gateway West segment D.1, which are currently operational. The preferred portfolio also includes future transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of low-cost resource options and relieves stress on current assets.

## Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong history of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp's resource planning and energy supply teams work closely with regional partners and ensure that there is sufficient supply to serve customers, while transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west to ensure that PacifiCorp can deliver power safely to customers now and in the future.

## Supply-Based Reliability

### Regional Resource Adequacy

As part of its 2025 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information.

In December 2024 the Western Electricity Coordinating Council (WECC) published the Western Assessment of Resource Adequacy (WARA), which serves as an interconnection-wide assessment of resource adequacy as discussed below. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

## WECC Western Assessment of Resource Adequacy Report

The WECC WARA was published in December 2024 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years.[1] The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. A key driver of the results is the forecasted growth in load across the west, which is projected to increase by over 20.4% in the next ten years (on an energy basis), more than double the 9.6% growth forecast from the 2022 WARA. PacifiCorp's loads are located in the NW-Northwest and NW-Central regions evaluated as part of the WARA. Peak demand in the NW-Northwest region is forecasted to grow by 13.5% in the next ten years, while the NW-Central region is forecasted to grow by 8.5% over the same time. While significant, these are both lower than the growth of the Western Interconnection as whole, where growth is projected at 17.2%, driven by increases in California and the Desert Southwest.

Resource plans have identified a vast quantity of resources to meet this demand, 172 GW of new generation resources, which is more than double the generation capacity added in the last ten years. Plans include 68 GW of solar capacity additions in the next ten years, while will nearly triple the 35 GW in operation in 2023, plus 40 GW of wind capacity additions in the next ten years, relative to 37 GW in operation in 2023. Similarly, battery storage is projected to grow by 37 GW. The WARA highlights concerns that planned resources will not be brought online in a timely manner and includes four scenarios evaluating various levels of resource build out.

In the "All Additions" scenario, which includes all planned resources, the WARA identifies risks in the NW-Northwest region, primarily in the winter, and primarily in 2029 and later. Risks increase and appear in other regions if lower levels of planned resources are achieved, as summarized in Table 5.1.

**Table 5.1 – WARA Demand-at-Risk Summary[2]**

| | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **55% Resource Additions Scenario** | | | | | | | | | | | |
| Region | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| California | - | - | - | - | - | - | - | - | - | - | - | - |
| Desert Southwest | - | - | - | - | - | - | Medium | Medium | Low | - | - | - |
| NW-Northwest | High | High | Medium | Low | - | - | Low | Medium | Medium | High | High | High |
| NW-Northeast | - | Low | - | - | - | - | Low | Medium | - | - | - | - |
| NW-Central | - | - | - | - | - | Low | Medium | Medium | Medium | - | - | - |
| | Month | | | | | | | | | | | |
| | **85% Resource Additions Scenario** | | | | | | | | | | | |
| Region | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| California | - | - | - | - | - | - | - | - | - | - | - | - |
| Desert Southwest | - | - | - | - | - | - | - | - | - | - | - | - |
| NW-Northwest | Medium | Medium | - | - | - | - | - | Low | - | Medium | Low | Medium |
| NW-Northeast | - | Low | - | - | - | - | - | Low | - | - | - | - |
| NW-Central | - | - | - | - | - | Low | Low | Low | Medium | - | - | - |

Risk reflects the count of hours in each month that exceed a one-day-in-ten-years threshold by 2034.

High >50 hours Medium 10-49 hours Low <10 hours

[1] WECC. Western Assessment of Resource Adequacy 2024. Available online: https://feature.wecc.org/wara/ (accessed 12/18/2024)

[2] WECC. WARA 2024 Demand-at-Risk Hours by Subregion. Available online at: https://www.wecc.org/wecc-document/17071 (Accessed 12/18/2024)

The NW-Northwest and NW-Central regions which include PacifiCorp's load both have hours at risk. In the NW-Northwest region, significant risk exists in both the summer and winter seasons. While PacifiCorp has significant transfer capability into the NW-Northwest and proportionately lower dependence on hydropower than the NW-Northwest region as a whole, regional capacity limitations would result in less margin for error. In the NW-Central region, risks are somewhat lower, and concentrated in the summer, but still indicate that incremental resources are necessary to serve growing loads. The results shown assume import capability between sub-regions – in the absence of imports, risks are high in the NW-Northwest and NW-Central regions even if all planned new resources are built.

The WARA characterizes four risks that impact planned resource additions: supply chain disruptions, interconnection queue, siting delays, and increased costs. Some of the impacts are reduced because of PacifiCorp's particular circumstances. PacifiCorp's relatively large portfolio and geographic footprint create a wider range of opportunities than are available to many other utilities, increasing the likelihood that some new projects will be able to proceed. This is bolstered by PacifiCorp's implementation of a cluster study interconnection process in 2020, which has enabled large numbers of interconnection requests to be processed more quickly than was possible in the past, increasing the likelihood that projects will be available in desired timeframes. After cost-effective projects are identified, PacifiCorp's relatively large demand allows it to contract with multiple developers for multiple sites, reducing the impact if any single developer or site falls through or is delayed. That said, substantial risks remain for any resource additions.

The WARA also characterizes risks associated with other factors: resource variability, transmission considerations, energy policy, and extreme weather. The limitations of wind, solar, and energy-limited resources like energy storage are different from those of baseload or dispatchable resources, and those limitations become more restrictive as the share of these resources increases. Given the expected tripling of solar capacity and doubling of wind capacity, variability is expected to increase significantly. The variability and operational requirements of that future resource mix is not fully characterized and could be impacted further by extreme weather events. The other risk factors cover a range of planning and policy considerations, and the process through which resource and transmission build outs are implemented. Utility planning and procurement takes time, and the build out of resources and transmission is reliant upon a range of state and federal processes and requirements.

## NERC Long-Term Reliability Assessment (LTRA)

**Resources**

As part of the regional reliability assessment to support the 2025 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2024.[3] The NERC LTRA organizes prospective resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

- Tier 1: resources under construction, or with signed contracts.
- Tier 2: resources with completed interconnection studies.
- Tier 3: resources in an interconnection queue that do not meet the Tier 2 requirement.

Planning Reserve Margin

The LTRA defines "planning reserve margin" as the difference between resources and demand, divided by demand, expressed as a percentile.

Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- High Risk: shortfalls may occur at normal peak conditions.
- Elevated Risk: shortfalls may occur in extreme conditions.
- Normal Risk: low likelihood of electricity supply shortfall.

**WECC Subregions**

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

**Table 5.2 – WECC Subregion Descriptions**

| Designation | Subregion | Country | Peak |
|---|---|---|---|
| NW | The rest of WECC, beyond the exceptions listed below | United States | Summer |
| SW | Primarily Arizona and New Mexico | United States | Summer |
| CA/MX | California / Mexico | United States | Summer |
| AB | Alberta | Canada | Winter |
| BC | British Columbia | Canada | Winter |

**LTRA WECC Assessment**

Table 5.3 presents the WECC LTRA assessments for the three WECC subregions that include the United States. Anticipated Reserve Margin is based on existing resources, firm transfers, and Tier 1 additions, less confirmed retirements. Prospective Reserve Margin adds existing resources without firm transmission, or with other potential limitations, likely transfers, and Tier 2 capacity additions, less unconfirmed retirements. Values that fall below the reference margin level (i.e. planning target) are highlighted.

[3] NERC. 2024 Long-Term Reliability Assessment. December 2024. Available online at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed 12/18/2024)

**Table 5.3 – NERC LTRA for Selected WECC Subregions**

WECC-NW

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Anticipated Reserve Margin (%) | 38.7% | 37.7% | 34.1% | 29.3% | 23.3% | 17.0% | 10.8% | 8.9% | 6.7% | 4.6% |
| Prospective Reserve Margin (%) | 39.9% | 40.6% | 37.8% | 34.2% | 30.0% | 25.7% | 20.4% | 18.4% | 15.7% | 13.9% |
| Reference Margin Level (%) | *16.3%* | *15.8%* | *15.9%* | *15.4%* | *14.7%* | *14.5%* | *14.3%* | *14.2%* | *14.4%* | *13.8%* |

WECC-SW

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Anticipated Reserve Margin (%) | 36.9% | 35.6% | 31.8% | 24.2% | 17.4% | 11.3% | 7.7% | 0.2% | -4.7% | -8.7% |
| Prospective Reserve Margin (%) | 38.6% | 40.1% | 38.2% | 31.1% | 26.7% | 20.4% | 16.8% | 9.2% | 4.9% | 0.0% |
| Reference Margin Level (%) | *11.0%* | *10.8%* | *12.0%* | *11.7%* | *10.2%* | *10.1%* | *9.9%* | *9.7%* | *10.8%* | *9.4%* |

WECC-CA/MX

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Anticipated Reserve Margin (%) | 45.8% | 45.2% | 38.4% | 43.1% | 28.8% | 29.6% | 23.3% | 25.0% | 15.2% | 11.1% |
| Prospective Reserve Margin (%) | 51.8% | 55.1% | 48.2% | 62.5% | 45.6% | 57.9% | 51.0% | 59.0% | 50.2% | 47.3% |
| Reference Margin Level (%) | *17.4%* | *17.4%* | *16.4%* | *17.4%* | *16.6%* | *16.4%* | *16.1%* | *16.3%* | *14.9%* | *15.3%* |

As shown, the WECC-NW subregion that includes PacifiCorp's load meets the reference margin with anticipated resources through 2030, and with prospective resources through the ten-year horizon. The WECC-SW subregion also meets the reference margin with anticipated resources through 2030 but only has sufficient prospective resources through 2031. The WECC-CA/MX region meets the reference margin with anticipated resources through 2033, and with prospective resources through the ten-year horizon. While this presents a relatively favorable view of supply and demand, the LTRA definition of Tier 1 resources includes everything with an interconnection agreement and/or power purchase agreement. Not all such resources will ultimately be brought online in a timely manner. The factors identified the WECC WARA (supply chain disruptions, interconnection queue, siting delays, and increased costs) can all derail projects that are otherwise feasible.

## Pacific Northwest Power Supply Adequacy Assessment

The Northwest Power and Conservation Council released its 2029 Adequacy Assessment in August 2024.[4] Starting in 2011, an annual loss-of-load-probability of up to five percent was deemed adequate. Starting with the 2023 assessment a multi-metric framework of shortfall frequency, duration, and magnitude was used. These metrics include:

- **Loss of load events (LOLEV):** limits the expected frequency of shortfall events to protect against frequent use of emergency measures.
- **Duration Value at Risk**: limits shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
- **Peak Value at Risk**: limits maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
- **Energy Value at Risk**: limits total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

An adequate system must meet all these metrics. The 2029 Adequacy Assessment is based on the 2021 Northwest Power Plan, discussed below, with updates for expected changes through 2029, including load growth, resource development, and transmission. Based on updated results for adequacy in year 2029, the 2029 Adequacy Assessment concludes that power supply would be

[4] Northwest Power and Conservation Council. Pacific Northwest Power Supply Adequacy Assessment for 2029. August 2024. Available online at: https://www.nwcouncil.org/fs/18853/2024-4.pdf (accessed 12/18/2024)

adequate under reference conditions. This conclusion is in part based on coal plants changing to natural gas, rather than retiring (including Jim Bridger 1 and 2, which were converted in 2024). The 2029 Adequacy Assessment identifies two scenarios that could lead to reliability shortfalls. First, if energy efficiency savings only meet the low end of the targeted quantity, shortfall risks increase in the winter. Second, higher data center loads in the absence of commensurate resource supply could lead to reliability shortfalls in both the winter and the summer. An additional potential risk is related to the Boardman-to-Hemingway project which the 2029 Adequacy Assessment assumes is operational by 2029, increasing transfer capability between Idaho and the Pacific Northwest, as this upgrade is not part of PacifiCorp's 2025 IRP preferred portfolio. The metric results from the 2029 Adequacy Assessment are provided in Table 5.4, with shortfalls highlighted in orange.

**Table 5.4 – Northwest Power and Conservation Council 2029 Adequacy Assessment**

| Type | Metric | Threshold | Reference | Low End EE | Higher Data Center |
|---|---|---|---|---|---|
| Frequency | Winter LOLEV | 0.1 | 0.022 | 0.35 | 1.294 |
| Frequency | Summer LOLEV | 0.1 | 0.017 | 0.033 | 0.3 |
| Duration | Duration VaR 97.5 | 8 hours | 0 | 1.5 | 20.6 |
| Magnitude | Peak VaR 97.5 | 1200 MW | 0 | 1,567 | 3,076 |
| Magnitude | Energy VaR 97.5 | 9600 MWh | 0 | 4,196 | 196,324 |

## Western Resource Adequacy Program (WRAP)

The WRAP is a regional reliability planning and compliance program, intended to help facilitate region-wide resource adequacy, and initiated on behalf of the utilities that are part of the Western Power Pool (formerly the Northwest Power Pool). WRAP allows for coordination and visibility of resource needs and supply among the participants, taking advantage of the diversity and sharing from pooling resources.

WRAP begins with regional analysis, as the program sets regional reliability metrics for upcoming seasons, including planning reserve margins that are applied to loads and qualifying capacity contributions that apply to resources. With those values in hand, utilities must secure resources and, seven months prior to the start of a winter or summer season, must submit a forward showing demonstrating they have resources and transmission to cover their load and planning reserve margin requirements. Time is provided to cover shortfalls before the season begins. Within the season, an operational component allows those participants with a day-ahead resource shortfall to call upon the program and receive incremental resources from participants who have a surplus.

WRAP is based on two seasons: summer (June through September) and winter (November through March). Planning reserve margins vary by month, and by region, as WRAP covers two regions: the Pacific Northwest (primarily Oregon and Washington and British Columbia, with parts of northern Idaho and Montana) and the Desert Southwest, including the remainder of Idaho, Utah, Wyoming, Colorado, Nevada, and Arizona. Similarly, monthly qualifying capacity contributions are calculated for each resource, and capture technology type, regional variations, and resource-specific performance. For example, wind and solar contributions incorporate a resource's output

during capacity critical hours (the highest load hours after netting out wind, solar, and run of river hydro generation).

As of September 2024, the Western Power Pool Board of Directors has approved updates to the WRAP tariff along with seven business practice manuals detailing of the program will operate. WRAP is currently operational with non-binding requirements and has plans in place to enable fully binding operations in Summer 2027 for participants that provide notice of their intent by January 2026. All participants will be binding for Winter 2027-2028 (i.e. starting November 2027). If a WRAP Participant chooses to exit the program, a two-year exit period applies. Current WRAP Participants have until October 31st, 2025, to exit the program without being subject to a financially binding season.

PacifiCorp is currently participating in WRAP and is working with the Western Power Pool to address outstanding issues, including the interaction between WRAP and the CAISO's Enhanced Day-Ahead Market (EDAM) and complexity from PacifiCorp's footprint spanning both WRAP regions. While issues remain, PacifiCorp's 2025 IRP includes modeling to capture WRAP compliance requirements starting in 2028 and continuing through the study horizon. While proxy resource selections within the 2025 IRP can only begin on January 1st of each year, actual resource procurement could be targeted to the November 2027 start date to the extent necessary, or short-term products could be used to address unmet requirements, if any.

## Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp previous IRP modeling has included front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions. However, market transactions that are not based on a specified source do not provide qualifying capacity for WRAP compliance. While other short-term products exist, such as slices of hydropower projects on the Mid-Columbia or tolling agreements for merchant-owned natural gas plants, there are relatively few such opportunities and there may be significant competition for such products given rising demand and stricter resource adequacy requirements under WRAP. With that in mind, for the 2025 IRP, PacifiCorp is not including short-term market products as options for WRAP compliance.

WRAP compliance does not guarantee reliability, in particular a monthly qualifying capacity contribution value does not ensure resources will be available to meet hourly requirements such as the hourly balancing test in the EDAM. At the same time, PacifiCorp recognizes that increasing coordination of spot market transactions through EIM, EDAM, and WRAP is likely to provide significant economic benefits. To balance the limitations of market transactions for capacity and reliability requirements and the benefits of market transactions for regional dispatch, the 2025 IRP does not allow market purchases in certain key periods, but otherwise allows market purchases up to transmission limits. During the summer WRAP season (June through September), market purchases are not allowed from 4:00 p.m. to 12:00 a.m. on PacifiCorp's top five load days in each month. Similarly, in the winter WRAP season (November through March), market purchases are

not allowed from 4:00 a.m. to 8:00 a.m. as well as 4:00 p.m. to 12:00 a.m., again on PacifiCorp's top five load days in each month. For the 2025 IRP, PacifiCorp is also differentiating market prices within each month, to reflect historical patterns on the days used to derive the chaotic normal load forecast and reflecting the same weather conditions used to develop wind and solar generation profiles. In general, market prices are higher when load is high and wind and solar output is relatively low, though market prices reflect region-wide conditions of PacifiCorp's supply and demand is only a part. Market prices in EIM and EDAM will reflect the balance of supply-and-demand, and surplus supply from PacifiCorp is likely to result in lower market clearing prices. While this effect is not captured in PacifiCorp's hourly market price forecast, market sales for the 2025 IRP have been capped at historical average levels, since large surpluses would impact pricing.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, the company will continue to refine its assessments of market depth and liquidity for transactions to quantify the risk associated with the level of market reliance. Additional description is provided in Volume I, Chapter 7 (Resource Options); also, see the sensitivities discussion in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).

## Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2025 IRP to assess the ways in which climate change may impact planning assumptions.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2004 through 2023. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. These temperature changes lead to higher summer peaks and lower winter peaks, with increasing impacts across the study horizon. See Appendix A for additional detail regarding how climate change is incorporated into the load forecast.

## Weather-Related Impacts to Variable Generation

New for the 2025 IRP, all wind and solar generation profiles are based on historical weather conditions on the same historical day underlying the load forecast. This captures the relationship between load, wind, and solar that happened in recent history. Each month of the Company's chaotic normal load forecast reflects the range of weather conditions experienced in the most typical month from 2013-2022, while stochastic analysis for the 2025 IRP will reflect the range of weather conditions experienced in every year from 2006-2023. The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios. For the 2025 IRP, PacifiCorp is not projecting specific climate impacts on wind and solar generation but notes that recent history

may be more representative of future conditions than earlier conditions. As a result, reliability and system cost risks identified using inputs derived from recent historical years may be of greater concern as an indicator of future risk.

**Wildfire Impacts**

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

**Extreme Weather Impacts**

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to

modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

**Impacts on Wind and Solar Energy**

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[5] Some broad impacts anticipated from climate change are noted below:[6]

Wind Energy

- Changes to wind speed: could impact energy assessments.
- Changes in temperature: with increased temperatures the air density could reduce energy outputs.
- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand.

[5] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.

[6] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Rising sea levels: could damage offshore wind farm infrastructure.

Solar Energy

- Changes in mean temperatures: increased global temperatures could reduce cell efficiency.
- Changes in solar irradiation, dirt, snow, precipitation: increase in these variables could reduce energy output.

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

## Wildfire Risk Mitigation

PacifiCorp's Wildfire Mitigation Plans (WMPs) are designed to meet regulatory requirements while delivering safe and reliable power. These plans focus on enhancing situational awareness, implementing robust operational practices, and hardening the power system to mitigate wildfire risks while balancing customer and community impacts.[7]

### PacifiCorp Wildfire Mitigation Plan Regulatory Compliance

PacifiCorp meets regulatory requirements through the submittal of Wildfire Mitigation Plans (WMPs) with the specific regulatory alignments for each state stated below:

1. **California**: The WMP complies with California Senate Bill 901 and the California Public Utilities Commission (CPUC) provisions under Section 8386.
2. **Idaho**: The WMP was submitted in accordance with Idaho Public Utilities Commission Order No. 36045.
3. **Utah**: The WMP adheres to Utah Administrative Code R746-315-2, effective June 1, 2023, and complies with Subsection 54-24-201.
4. **Oregon**: The WMP meets the requirements set forth in Oregon Administrative Rule 860-300-0040.
5. **Washington**: The WMP was submitted on October 31, 2024, and compliance with statutory requirements was confirmed by the Washington Utilities and Transportation Commission as complying with the Revised Code of Washington (RCW) 80.28.440.

Although Wyoming does not have regulatory requirements for a wildfire mitigation plan, PacifiCorp has proactively filed one in conjunction with the general rate case.

### Core Principles

All WMPs are publicly accessible via the PacifiCorp Wildfire Mitigation Plan website (linked here). These plans detail the investments and strategies for constructing, maintaining, and operating electrical lines and equipment for wildfire mitigation projects and programs. While there

[7] Wildfire mitigation and impacts were discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

are state-specific requirements, the core strategy across all six states remains consistent, guided by the following principles:

- **Situational Awareness and Operational Readiness**: Implementing systems that enhance situational awareness, and operational readiness is crucial for mitigating fire risks and their impacts.
- **Operational Practices**: Minimizing the impact of fault events through rapid isolation using advanced equipment and trained personnel.
- **System Hardening**: Reducing the frequency of ignition events by engineering more resilient systems that experience fewer faults.

**Balancing Mitigation and Community Impact**

PacifiCorp is committed to balancing wildfire risk mitigation with the needs of customers and communities. Adjustments to power system operations, such as modifying protective device settings and testing protocols, are carefully considered to reduce wildfire risks. These measures are applied selectively to avoid unnecessary disruptions to the power supply.

The wildfire mitigation program approach includes deploying advanced technologies like fault indicators and assessing outages to inform short-term mitigation projects. These efforts are designed to enhance safety while maintaining reliable service.

PacifiCorp's Wildfire Mitigation Plans (WMPs) reflect the Company's dedication to balancing costs, benefits, operational impacts, and risk mitigation with the goal to provide safe, reliable, and affordable electric service, prioritizing the well-being of customers and communities.

## Transmission-Based Reliability

PacifiCorp is required to meet mandatory FERC, NERC, and WECC reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generating resources for reserve capacity to comply with mandatory reliability standards.

## Federal Reliability Standards

The Energy Policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in short-term (1-2 years), medium term (5 years) and long-term (10-20 years) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 as detailed in Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produce a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers. In 2024, FERC issued Order 1920 which will further expand regional planning processes, including a requirement for a long-term (20 year) regional plan. PacifiCorp is working with NorthernGrid members to draft tariff revisions to outline the expanded process in preparation for the FERC required compliance filing in August 2025.

## Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study if the study determines that mitigations are required due to retirement.

Past studies have found that several factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit designation/retirement is received, all such coal retirement analysis is considered preliminary.

# CHAPTER 6 – LOAD AND RESOURCE BALANCE

## CHAPTER HIGHLIGHTS

- New for the 2025 IRP, PacifiCorp is calculating its capacity position based on Western Resource Adequacy Program (WRAP) compliance requirements, with binding operations under the program expected to begin by 2028. WRAP participants with projected resource shortfalls on a day-ahead basis will be able to purchase from WRAP participants with excess supply.
- Every resource has a qualifying capacity contribution (QCC) for each month of the summer (June-September) and winter (November-March) seasons. These values are calculated by WRAP based on resource-specific historical performance and are based on the loads and resource mix of the regional participants. These values are updated by WRAP ahead of each compliance season.
- Seven months prior to the start of each season, WRAP participants must make a forward showing, demonstrating that the QCC for their resources is sufficient to meet their peak load plus a monthly planning reserve margin determined by WRAP.
- While WRAP is projected to enhance reliability by providing priority access to supply from other participants, the monthly QCC values do not ensure a utility will be reliable or have sufficient resources to meet its requirements from hour to hour, so hourly analysis of the load and resource balance is also necessary.
- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements.
- The company's load obligation is calculated based on projected load less distributed generation, energy efficiency savings, and demand response, including interruptible load.
- A distributed generation study prepared by DNV produced estimates on distributed generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2025 IRP load and resource balance reflects base case distributed generation penetration levels as a reduction in load.
- Relative to WRAP compliance requirements, PacifiCorp's system is capacity deficient (before adding proxy resources other than energy efficiency, and without considering short-term capacity procurement, i.e. market purchases) in the summer beginning in 2026, and the winter peaks throughout the planning horizon.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. PacifiCorp's 2025 IRP reflects renewable resource generation profiles based on the same patterns of historical weather conditions used to develop its load forecasts, both on a normalized basis and for stochastic analysis. While adjustments to account for climate change are included in the base forecast, customer demand may be further influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

# Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Appendix A (Load Forecast). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

# System Coincident Peak Load Forecast

**System Coincident Peak Load Forecast**

The system coincident peak load is the annual maximum hourly load on the system. The 2025 IRP relies on PacifiCorp's May 2024 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency. The system summer peak load grows at a compound annual growth rate (CAGR) of 1.67 percent over the period 2025 through 2044.

**Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency (MW)**

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | 11,318 | 11,270 | 11,425 | 11,553 | 11,690 | 11,844 | 12,104 | 12,193 | 12,363 | 12,575 |
| | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** |
| **System** | 12,819 | 13,134 | 13,404 | 13,693 | 13,978 | 14,279 | 14,581 | 15,008 | 15,237 | 15,518 |

# Existing Resources

## Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "End of Coal-fired Operation" reflects the year a resource must retire or converts to natural gas (if option is available) as reflected in modeling inputs.

**Table 6.2 – Coal-Fired Plants**

| Plant | PacifiCorp Percentage Share (%) | State | Nameplate Capacity (MW) | End of Coal-fired Operation |
|---|---|---|---|---|
| Colstrip 3 | 10 | Montana | 74 | 2025 (Transfer capacity to unit 4) |
| Colstrip 4 | 10* | Montana | 74 | 2029 (PacifiCorp exit) |
| Craig 1 | 19 | Colorado | 82 | 2025 (Assumed end of life) |
| Craig 2 | 19 | Colorado | 79 | 2028 (Assumed end of life) |
| Dave Johnston 1 | 100 | Wyoming | 99 | 2028 (Gas conversion option) |
| Dave Johnston 2 | 100 | Wyoming | 106 | 2028 (Gas conversion option) |
| Dave Johnston 3 | 100 | Wyoming | 220 | 2027 (Retire: Clean air compliance) |
| Dave Johnston 4 | 100 | Wyoming | 330 | |
| Hayden 1 | 24 | Colorado | 44 | 2028 (Assumed end of life) |
| Hayden 2 | 13 | Colorado | 33 | 2027 (Assumed end of life) |
| Hunter 1 | 94 | Utah | 418 | |
| Hunter 2 | 60 | Utah | 269 | |
| Hunter 3 | 100 | Utah | 471 | |
| Huntington 1 | 100 | Utah | 459 | |
| Huntington 2 | 100 | Utah | 450 | |
| Jim Bridger 3 | 67 | Wyoming | 349 | |
| Jim Bridger 4 | 67 | Wyoming | 351 | |
| Naughton 1 | 100 | Wyoming | 156 | 2025 (Gas conversion option) |
| Naughton 2 | 100 | Wyoming | 201 | 2025 (Gas conversion option) |
| Wyodak | 80 | Wyoming | 268 | |
| **TOTAL – Coal** | | | **4,533** | |

*PacifiCorp's share of Colstrip 4 is projected to include its current ownership of Colstrip 3 starting in 2026.

**Table 6.3 – Natural Gas-Fired Plants**

| Plant | PacifiCorp Percentage Share (%) | State | Nameplate Capacity (MW) |
|---|---|---|---|
| Chehalis | 100 | Washington | 500 |
| Currant Creek | 100 | Utah | 540 |
| Gadsby 1 | 100 | Utah | 64 |
| Gadsby 2 | 100 | Utah | 69 |
| Gadsby 3 | 100 | Utah | 105 |
| Gadsby 4 | 100 | Utah | 40 |
| Gadsby 5 | 100 | Utah | 40 |
| Gadsby 6 | 100 | Utah | 40 |
| Hermiston | 100 | Oregon | 237 |
| Jim Bridger 1 | 67 | Wyoming | 354 |
| Jim Bridger 2 | 67 | Wyoming | 359 |
| Lake Side | 100 | Utah | 580 |
| Lake Side 2 | 100 | Utah | 677 |
| Naughton 3 | 100 | Wyoming | 247 |
| **TOTAL – Natural Gas** | | | **3,852** |

## Renewable Resources

### Wind

PacifiCorp either owns or purchases under contract 5,154 MW of wind resources. Table 6.4 shows existing (or under construction) wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

**Table 6.4 – Owned Wind Resources**

| Utility-Owned Wind Projects | State | Capacity (MW) |
|---|---|---|
| Goodnoe Hills East | WA | 94 |
| Leaning Juniper | WA | 101 |
| Marengo I | WA | 156 |
| Marengo II | WA | 78 |
| Cedar Springs 2 | WY | 199 |
| Dunlap 1 | WY | 111 |
| Ekola Flats 1 | WY | 250 |
| Foote Creek I | WY | 41 |
| Glenrock I | WY | 99 |
| Glenrock III | WY | 39 |
| High Plains | WY | 99 |
| McFadden Ridge 1 | WY | 29 |
| Pryor Mountain | WY | 240 |
| Rolling Hills | WY | 99 |
| Seven Mile Hill | WY | 99 |
| Seven Mile Hill II | WY | 20 |
| TB Flats 1-2 | WY | 500 |
| Foote Creek II-IV | WY | 43 |
| Rock Creek I | WY | 190 |
| Rock Creek II | WY | 400 |
| Rock River | WY | 50 |
| **TOTAL – Owned Wind** | | **2,937** |

**Table 6.5 – Non-Owned Wind Resources**

| Power Purchase Agreements | State | PPA or QF | Capacity (MW) |
|---|---|---|---|
| Wolverine Creek | ID | PPA | 65 |
| Chopin-Schumann | WA | QF | 8 |
| Cedar Springs I | WY | PPA | 199 |
| Cedar Springs III | WY | PPA | 133 |
| Three Buttes Power | WY | PPA | 99 |
| Top of the World | WY | PPA | 200 |
| Meadow Creek Project Five Pine | ID | QF | 40 |
| Meadow Creek Project North Point | ID | QF | 80 |
| Latigo | UT | QF | 60 |
| Mountain Wind I | UT | QF | 61 |
| Mountain Wind II | UT | QF | 80 |
| Power County Park North | UT | QF | 23 |
| Power County Park South | UT | QF | 23 |
| Spanish Fork Park 2 | UT | QF | 19 |

| | | | |
|---|---|---|---|
| Tooele 1 and 2 | UT | QF | 3 |
| Big Top | WA | QF | 2 |
| Butter Creek Power | WA | QF | 5 |
| Chopin | WA | QF | 10 |
| Four Corners | WA | QF | 8 |
| Four Mile Canyon | WA | QF | 10 |
| Orchard 1 | WA | QF | 10 |
| Orchard 2 | WA | QF | 10 |
| Orchard 3 | WA | QF | 10 |
| Orchard 4 | WA | QF | 10 |
| Oregon Trail | WA | QF | 10 |
| Pacific Canyon | WA | QF | 8 |
| Sand Ranch | WA | QF | 10 |
| Three Mile Canyon | WA | QF | 8 |
| Wagon Trail | WA | QF | 3 |
| Ward Butte | WA | QF | 7 |
| BLM Rawlins | WY | QF | 0.1 |
| Pioneer Park I | WY | QF | 80 |
| Cedar Creek | ID | PPA | 152 |
| Anticline | WY | PPA | 101 |
| Boswell | WY | PPA | 320 |
| Cedar Springs IV | WY | PPA | 350 |
| **TOTAL – Purchased Wind** | | | **2217** |

### Solar

PacifiCorp has a total of 97 solar projects under contract representing 3,615 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 550 MW of battery storage. Table 6.6 list solar power purchase agreements, and through Table 6.7 through Table 6.9 list solar qualifying facilities for each relevant state.

**Table 6.6 – Solar Power Purchase Agreements**

| Power Purchase Agreements | | | |
|---|---|---|---|
| **Resource** | **State** | **Solar Capacity (MW)** | **Storage Capacity (MW)** |
| Black Cap | OR | 2 | - |
| Millican | OR | 60 | - |
| Old Mill | OR | 5 | - |
| Oregon Solar Incentive Project | OR | 9 | - |
| Prineville | OR | 40 | - |
| Appaloosa Solar IA | UT | 120 | - |
| Appaloosa Solar IB | UT | 80 | - |
| Castle Solar (Retail 1) | UT | 20 | - |
| Castle Solar (Retail 2) | UT | 20 | - |
| Cove Mountain | UT | 58 | - |
| Cove Mountain II | UT | 122 | - |
| Elektron Solar 20Yr | UT | 10 | - |
| Elektron Solar 25Yr | UT | 70 | - |
| Faraday | UT | 525 | 150 |
| Graphite | UT | 80 | - |
| Green River | UT | 400 | 400 |
| Hornshadow Solar I | UT | 100 | - |
| Hornshadow Solar II | UT | 200 | - |
| Horseshoe | UT | 75 | - |
| Hunter | UT | 100 | - |
| Milford | UT | 99 | - |
| Pavant III | UT | 20 | - |
| Rocket | UT | 80 | - |
| Sigurd | UT | 80 | - |
| **TOTAL – Power Purchase Agreements** | | **2375** | **550** |

## Table 6.7 – Solar Qualifying Facilities, Oregon

| Oregon Qualifying Facilities | | |
|---|---|---|
| **Resource** | **Solar Capacity (MW)** | **Storage Capacity (MW)** |
| 7 Mile Solar | 1 | - |
| Adams | 10 | - |
| Antelope Creek Solar | 2 | - |
| Bear Creek | 10 | - |
| Black Cap II | 8 | - |
| Blackwell Creek Solar* | 1 | - |
| Bly | 8 | - |
| Buckaroo Solar 1* | 3 | - |
| Buckaroo Solar 2* | 3 | - |
| Canyonville Solar 1* | 1 | - |
| Canyonville Solar 2* | 2 | - |
| Chapman Creek Solar* | 3 | - |
| Cherry Creek Solar* | 0.4 | - |
| Chiloquin Solar | 10 | - |
| Elbe | 10 | - |
| Goodling Community Solar* | 1 | - |
| Green Solar* | 3 | - |
| Hay Creek Solar* | 0.6 | - |
| Klamath Falls Solar 1 | 0.8 | - |
| Klamath Falls Solar 2 | 3 | - |
| Linkville Solar* | 3 | - |
| Merrill | 10 | - |
| Norwest Energy 2 (Neff) | 10 | - |
| Norwest Energy 4 (Bonanza) | 6 | - |
| Norwest Energy 7 (Eagle Point) | 10 | - |
| Norwest Energy 9 Pendleton | 6 | - |
| OR Solar 2, LLC (Agate Bay) | 10 | - |
| OR Solar 3, LLC (Turkey Hill) | 10 | - |
| OR Solar 6, LLC (Lakeview) | 10 | - |
| OR Solar 8, LLC (Dairy) | 10 | - |
| Orchard Knob Solar | 2 | - |
| OSLH Collier | 10 | - |
| Pilot Rock Solar 1* | 3 | - |
| Pilot Rock Solar 2* | 3 | - |
| Pine Grove Solar | 1 | - |
| Round Lake Solar | 1 | - |
| Skysol | 55 | - |
| Solorize Rogue* | 0.1 | - |
| Sunset Ridge Solar | 2 | - |
| Tumbleweed | 10 | - |
| Tutuilla Solar* | 2 | - |
| Wallowa County* | 0.4 | - |
| Whisky Creek Solar* | 0.2 | - |
| Wocus Marsh Solar* | 0.9 | - |
| Wood River Solar* | 0.4 | - |
| Woodline Solar | 8 | - |
| **TOTAL – Oregon Solar QF Resources** | **264** | **0** |

*New project added in 2025 IRP

**Table 6.8 – Solar Qualifying Facilities, Utah**

| Utah Qualifying Facilities | | |
|---|---|---|
| **Resource** | **Solar Capacity (MW)** | **Storage Capacity (MW)** |
| Beryl | 3 | - |
| Buckhorn | 3 | - |
| CedarValley | 3 | - |
| Enterprise | 80 | - |
| Escalante I | 80 | - |
| Escalante II | 80 | - |
| Escalante III | 80 | - |
| Ewauna | 1 | - |
| Ewauna II | 3 | - |
| Granite Mountain - East | 80 | - |
| Granite Mountain - West | 50 | - |
| GranitePeak | 3 | - |
| Greenville | 2 | - |
| Iron Springs | 80 | - |
| Laho | 3 | - |
| Milford 2 | 3 | - |
| Milford Flat | 3 | - |
| Pavant | 50 | - |
| Pavant II | 50 | - |
| Quichapa I | 3 | - |
| Quichapa II | 3 | - |
| Quichapa III | 3 | - |
| Red Hill | 80 | - |
| South Milford | 3 | - |
| SunE1 | 3 | - |
| SunE2 | 3 | - |
| SunE3 | 3 | - |
| Three Peaks | 80 | - |
| **TOTAL – Utah Solar QF Resources** | **838** | **0** |

**Table 6.9 – Solar Qualifying Facilities, Wyoming**

| Wyoming Qualifying Facilities | | |
|---|---|---|
| **Resource** | **Solar Capacity (MW)** | **Storage Capacity (MW)** |
| Sage I | 20 | - |
| Sage II | 20 | - |
| Sage III | 18 | - |
| Sweetwater | 80 | - |
| **TOTAL – Wyoming Solar QF Resources** | **138** | **0** |

## Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW,

was completed at the end of 2007. The Oregon Institute of Technology has a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

**Biomass/Biogas**

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

**Distributed Generation Resources**

Table 6.10 provides a breakdown of distributed generation capacity and customer counts from data collected as of March 31, 2024. In addition to resources, PacifiCorp's customers also have over 60 MW of battery storage capacity. For forecasted growth in distributed generation and storage, please refer to Appendix L (Distributed Generation Study).

**Table 6.10 – Distributed generation Customers and Capacity**

| Fuel | Solar | Wind | Gas[1] | Hydro | Mixed[2] |
|---|---|---|---|---|---|
| Nameplate (kW) | 772,160 | 847 | 784 | 965 | 1,233 |
| Capacity (percentage of total) | 99.51% | 0.11% | 0.10% | 0.12% | 0.16% |
| Number of customers | 86,449 | 192 | 3 | 21 | 63 |
| Customer (percentage of total) | 99.68% | 0.22% | 0.00% | 0.02% | 0.07% |

[1] Gas includes: biofuel, waste gas, and fuel cells

[2] Mixed includes projects with multiple technologies, one project is solar and biogas, and the others are solar and wind

## Energy Storage

In addition to the battery storage contracted with solar resources listed in Table 6.6 PacifiCorp has existing or committed battery storage projects totaling approximately 523 MW of nameplate capacity, as shown in Table 6.11.

**Table 6.11 – Storage Resources**

| Power Purchase Agreements / Exchanges | State | Technology | Capacity (MW) |
|---|---|---|---|
| Dominguez Storage* | UT | Battery | 200 |
| Enterprise* | UT | Battery | 80 |
| Escalante* | UT | Battery | 80 |
| Granite Mountain* | UT | Battery | 80 |
| Iron Springs* | UT | Battery | 80 |
| Panguitch | UT | Battery | 1 |
| Oregon Institute of Technology (OIT) | OR | Battery | 2 |
| **TOTAL – Purchased Battery** | | | **523** |

*New project added in 2025 IRP

## Hydroelectric Generation

PacifiCorp owns or purchases over 1,200 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that

can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity available from hydroelectric plants is dependent upon several factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control.

**Table 6.12 – PacifiCorp Hydroelectric Generation Facilities**

| Plant | River System | State | Capacity (MW) |
|---|---|---|---|
| **East - Owned** | | | |
| Cutler | Bear | UT | 29 |
| Grace | Bear | UT | 33 |
| Oneida | Bear | UT | 27.9 |
| Soda | Bear | UT | 14 |
| Small East [1/] | Other | UT | 20.5 |
| **West - Owned** | | | |
| Bend | Other | OR | 1 |
| Big Fork | Other | MT | 4.6 |
| Swift 1 [2/] | Lewis | WA | 263.6 |
| Yale | Lewis | WA | 163.6 |
| Merwin | Lewis | WA | 151 |
| Clearwater 1 | N. Umpqua | OR | 17.9 |
| Clearwater 2 | N. Umpqua | OR | 31 |
| Fish Creek | N. Umpqua | OR | 10.4 |
| Lemolo 1 | N. Umpqua | OR | 32 |
| Lemolo 2 | N. Umpqua | OR | 38.5 |
| Slide Creek | N. Umpqua | OR | 18 |
| Soda Springs | N. Umpqua | OR | 11.6 |
| Toketee | N. Umpqua | OR | 45 |
| Eagle Point | Rogue | OR | 2.8 |
| Prospect 1 | Rogue | OR | 4.6 |
| Prospect 2 | Rogue | OR | 36 |
| Prospect 3 | Rogue | OR | 7.7 |
| Prospect 4 | Rogue | OR | 0.9 |
| Fall Creek | Other | OR | 2 |
| Wallowa Falls | Other | OR | 1.1 |
| | | **Total Owned** | **968** |
| **Qualifying Facilities (QF)** | | | |
| QF | Various | CA | 9.4 |
| QF | Various | ID | 22.7 |
| QF | Various | OR | 40 |
| QF | Various | UT | 2.2 |
| QF | Various | WA | 2.9 |
| Mid-Columbia | Columbia | WA | 170 |
| | | **Total QF** | **247** |
| **Total Hydroelectric** | | | **1215** |

[1/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.

[2/] Cowlitz County PUD owns Swift No. 2 and is operated in coordination with other Lewis River projects by PacifiCorp.

## Demand-Side Management/Distributed Generation

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories, or "classes." These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Modeling includes program drop-out rate and event non-performance rate assumptions to account for program parameters. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program. These are considered Class 1 DSM resources.

- **Energy Efficiency—Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at businesses. The savings are considered firm over the life of the improvement or customer action. These are considered Class 2 DSM resources.

- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. These are considered Class 3 DSM resources.

- **Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Like price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs. These are considered Class 4 DSM resources.

PacifiCorp has been operating successful DSM programs since the late 1970s. Over time, PacifiCorp's DSM acquisition has grown in investment levels, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 6.13 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.13 is shown as having zero MW.[1] Similarly, demand response resources available to the preferred portfolio, are characterized as incremental to Table 6.13. For a summary of current DSM program offerings in each state, refer to Appendix D (Demand-Side Management Resources).

[1] The historical effects of previous energy efficiency savings are captured in the load forecast before the modeling for new energy efficiency.

**Table 6.13 – Existing DSM Resource Summary**

| Program | Description | Energy Savings or Capacity at Generator | Included as Existing Resources for 2025-2045 Period |
|---|---|---|---|
| **Demand Response** | Residential/small commercial air conditioner load control | 135 MW summer[1/] | Yes. |
| | Irrigation load management | 200 MW summer | Yes. |
| | Interruptible contracts | 136 MW summer | Yes. |
| | Wattsmart® Batteries | 32 MW summer | Yes. |
| | Wattsmart® Business | 45 MW summer | Yes. |
| **Energy Efficiency** | PacifiCorp and Energy Trust of Oregon programs | 0 MW | No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio. |
| **Price Response and Load Shifting** | Time-based pricing | Energy and capacity impacts are not available/measured. | No. Historical savings from customer responses to pricing signals are reflected in the load forecast. |
| | Inverted rate pricing | Energy and capacity impacts are not available/measured. | No. Historical savings from customer response to pricing structure is reflected in load forecast. |
| **Education and Information** | Energy education | Energy and capacity impacts are not available/measured. | No. Historical savings from customer participation are reflected in the load forecast. |

[1/] A/C load control is based on long duration event characterization which assumes 50% cycling of ACs. A faster event (<1 hr) is characterized as 270 MW within the model.

## Distributed Generation Forecast

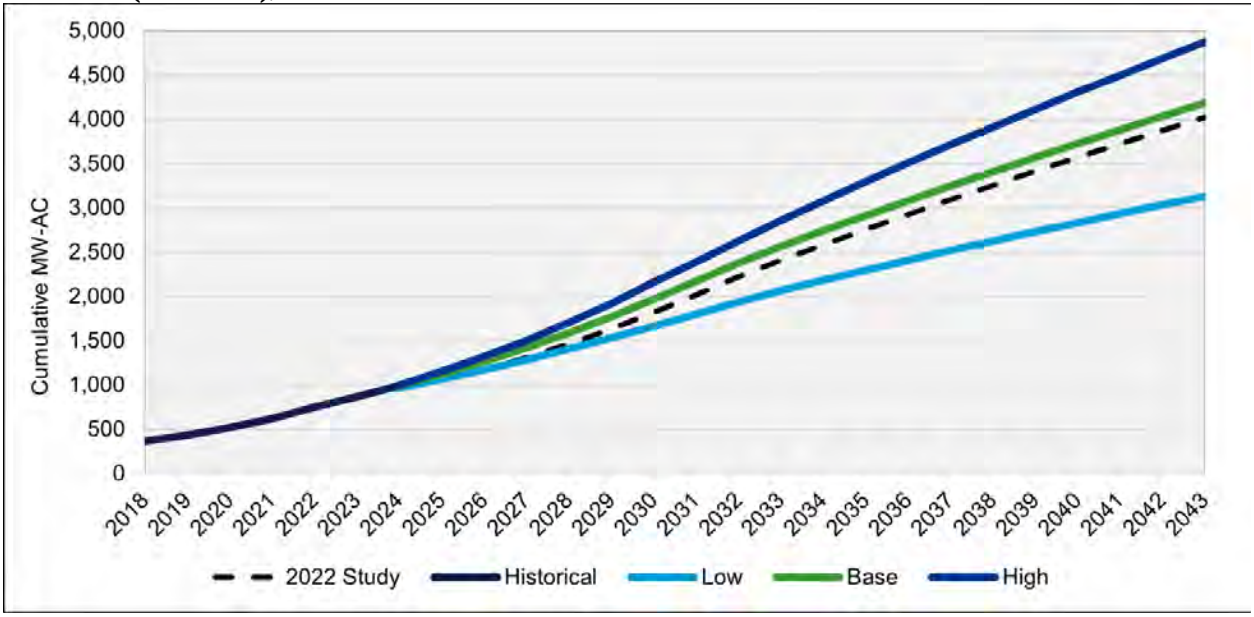
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

[2] In the 2023 IRP, this study was referred to as the "Private Generation" assessment.
[3] See Appendix L (Distributed Generation Study).
[4] PacifiCorp's and DNV's decisions in the development of the DG study were topics of discussion in the 2025 IRP public input meeting series and stakeholder feedback.
See Appendix M, stakeholder feedback form #6 (Renewable Northwest).
See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon).
See Appendix M, stakeholder feedback form #26 (Vote Solar).

DNV estimates approximately 4.18 gigawatts (GW) of DG capacity will be installed in PacifiCorp's service area by 2043 in the base case scenario. As shown in Figure 6.1, the low and high scenarios project a cumulative installed capacity of 3.12 GW and 4.87 GW by 2043, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for distributed generation that creates favorable economics for adoption and is incorporated into each case. The DNV study identifies expected levels of customer-sited DG, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

See Appendix L for the full DNV Distributed Generation report.

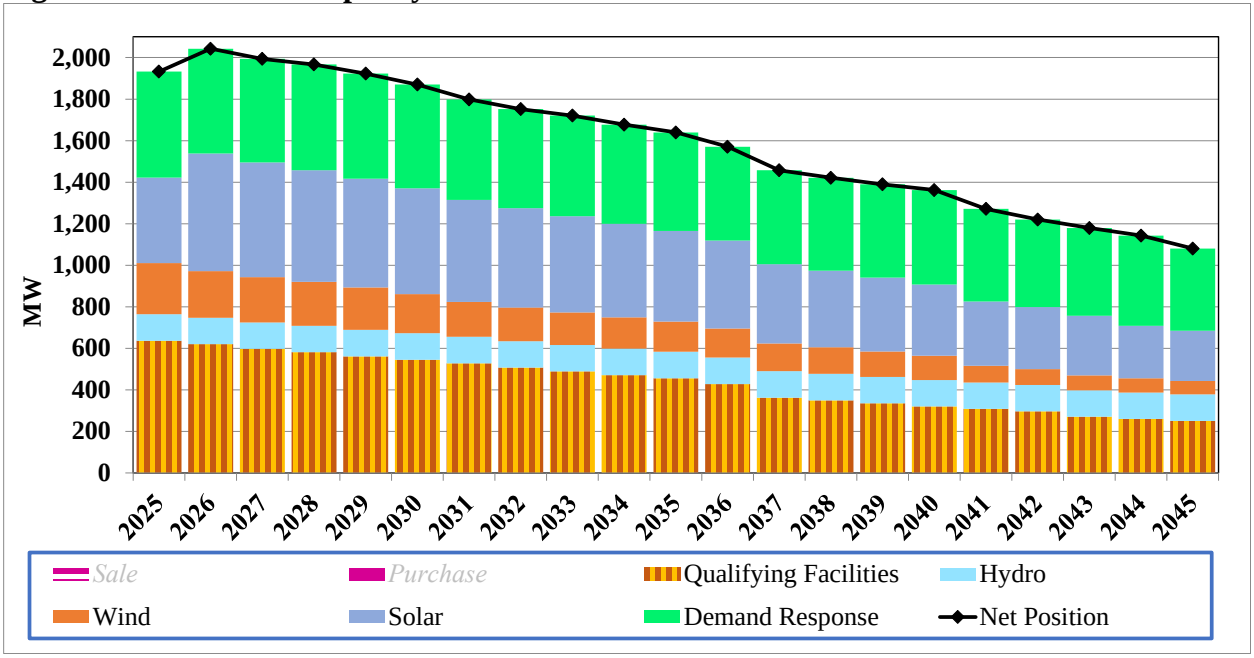
**Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043**




## Power-Purchase Agreements

PacifiCorp also meets capacity and energy requirements through long-term firm contracts. Figure 6.2 presents the contract capacity in place for 2025 through 2045. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. After their current contract terms, QF contracts are extended at a reduced level that reflects the historical renewal rate of 75%. All contracts are shown at their peak capacity contribution levels.

**Figure 6.2 – Contract Capacity in the 2025 IRP Summer Load and Resource Balance**




# Capacity Load and Resource Balance

## Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations to the annual capability of PacifiCorp's existing resources after retirements and future energy efficiency savings from the 2025 IRP preferred portfolio, and without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP, the load and resource balance use values from the Western Resource Adequacy Program (WRAP). WRAP calculates project-specific qualifying capacity contribution values for all existing and contracted resources, and those values are used where data is available. WRAP also provides the average contribution for wind, solar, energy storage and run of river hydro in different geographic areas, and these estimates are used for proxy resources in the 2025 IRP. WRAP will update the capacity contributions for resources ahead of each season, reflecting the current resource mix of the WRAP footprint through time. WRAP has also provided projections for future years and different resource penetration levels – as the penetration of wind, solar, and storage increases, contributions are expected to decline. Significant uncertainty remains, due to resource mix and timing, along with indirect factors like climate impacts on load and hydro. To better reflect future WRAP compliance requirements, PacifiCorp used the projections provided by WRAP to estimate contributions in 2045 based on the regional resource mix developed as part of the forward price curve used in the 2025 IRP. Because PacifiCorp is a relatively small portion of the regional resource mix, the calculation is static and does not vary with PacifiCorp's specific portfolio selections. WRAP contributions fall linearly from the current values for 2025 to the projected values for 2045. Additional detail is provided in Appendix K (Capacity Contribution).

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly distributed generation projections to determine the net

system coincident peak load for each of the first ten years (2025-2034) of the planning horizon. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are included as part of the existing resources. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (14.4% for the 2025 IRP, reflecting the WRAP value for the month of July) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

## Load and Resource Balance Components

The main component categories consist of the following: resources, obligation, reserves, position, and available market purchases.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—coal, gas, hydroelectric, wind, solar, other renewables, storage, QFs, demand response, and purchases. Categories in the obligation section include load, distributed generation, and energy efficiency from the preferred portfolio.

***Demand Response***

Existing demand response program capacity is categorized as a resource. Under WRAP, demand response must be designated as either a load reduction, where any impacts are captured in peak loads, or as a resource, based on its availability and duration during peak conditions. For the 2025 IRP, demand response is used for operating reserves and dispatched within the PLEXOS model based on economic need and is not targeted to reduce summer-time peak loads which often occur during solar generation hours when net demand is lower. As a result, treatment as a resource provides a larger capacity benefit currently. PacifiCorp expects to continue evaluating this as the WRAP gets underway, as some demand response programs may be suitable for peak load reduction. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

**Obligation**

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less distributed generation and energy efficiency from the preferred portfolio. The following are descriptions of each of these components:

***Load Net of Distributed generation***

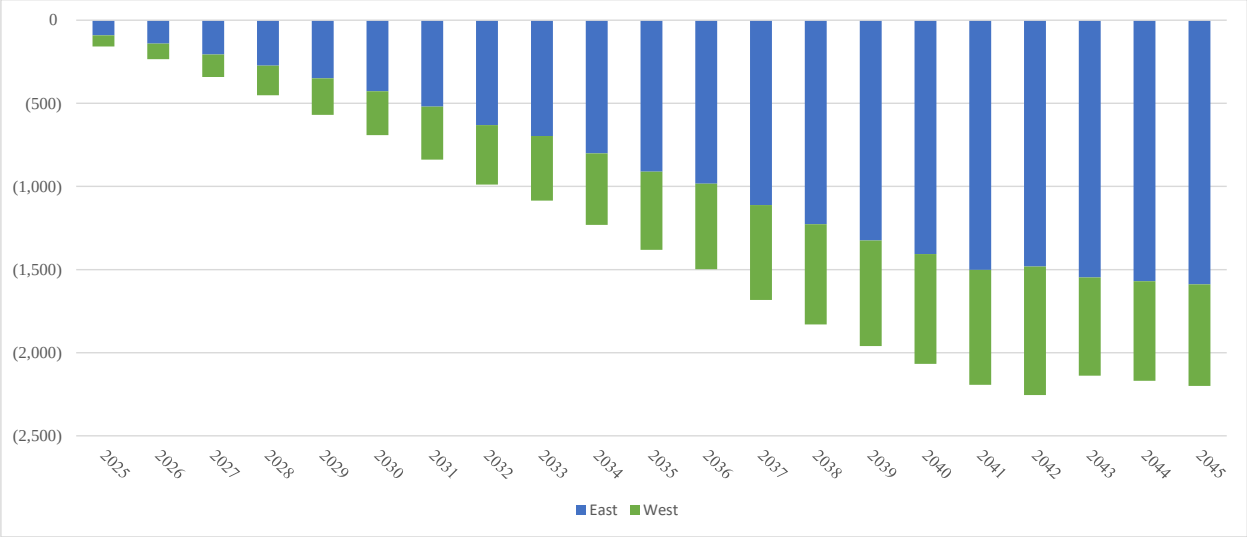
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks.

***Energy Efficiency***

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2024 energy efficiency that is not incorporated in the forecast. The 2024 energy efficiency forecast has been added to the energy efficiency line along with the energy efficiency selected in the 2025 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2025 IRP preferred portfolio.

**Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)**




***Planning Reserve Margin***

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

**Position**

The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources.

## Capacity Balance Determination

**Methodology**

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

**Existing Resources** = Coal + Gas + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities + Demand Response

The peak load, distributed generation, energy efficiency (from the preferred portfolio) are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

**Obligation** = Load – Distributed generation – Energy Efficiency

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 14.4 percent PRM for July and 16.8 percent PRM for December adopted from WRAP for the 2025 IRP. The formula for this calculation is:

**Planning Reserves** = Obligation x PRM

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, including available Market purchases, as shown in the following formula:

**Capacity Position** = (Existing Resources + Available Market purchases) – (Obligation + Planning Reserves)

**Capacity Balance Results**

Table 6.14 and Table 6.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 14.4 percent in the summer and 16.8 percent in the winter to calculate the planning reserve amount.[5] Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis up to the limits of the transfer capability between the two areas. Also note that QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewable, or other line items.

[5] PacifiCorp acknowledged errors in its 2023 IRP load and resource balance, which have been addressed in the 2025 IRP. See Appendix M, stakeholder feedback form #12 (Utah Association of Energy Users).

## Table 6.14 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,960 | 3,567 | 3,567 | 3,375 | 3,090 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 |
| Gas | 2,984 | 3,294 | 3,294 | 3,294 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 587 | 613 | 596 | 578 | 561 | 534 | 503 | 487 | 470 | 453 |
| Solar | 342 | 499 | 487 | 475 | 463 | 452 | 440 | 428 | 416 | 404 |
| Other Renewable | 46 | 45 | 44 | 42 | 41 | 40 | 39 | 37 | 36 | 35 |
| Storage | 1 | 939 | 925 | 909 | 894 | 879 | 865 | 849 | 834 | 819 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 405 | 394 | 383 | 372 | 361 | 351 | 340 | 328 | 314 | 301 |
| Demand Response | 451 | 446 | 440 | 452 | 450 | 443 | 429 | 423 | 431 | 425 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (274) | (1,440) | (1,361) | (1,096) | (902) | (631) | (476) | (421) | (380) | (277) |
| **East Existing Resources** | **8,578** | **8,433** | **8,452** | **8,479** | **8,504** | **8,540** | **8,611** | **8,603** | **8,592** | **8,632** |
| Load | 7,746 | 7,655 | 7,781 | 7,919 | 8,068 | 8,234 | 8,447 | 8,609 | 8,528 | 8,700 |
| Distributed Generation | (157) | (143) | (186) | (234) | (285) | (341) | (400) | (458) | (321) | (354) |
| Energy Efficiency | (91) | (141) | (206) | (274) | (349) | (428) | (520) | (631) | (696) | (801) |
| **East Total obligation** | **7,498** | **7,372** | **7,388** | **7,412** | **7,433** | **7,465** | **7,527** | **7,520** | **7,511** | **7,545** |
| **Planning Reserve Margin (14.4%)** | 1,080 | 1,062 | 1,064 | 1,067 | 1,070 | 1,075 | 1,084 | 1,083 | 1,082 | 1,087 |
| **East Obligation + Reserves** | 8,578 | 8,433 | 8,452 | 8,479 | 8,504 | 8,540 | 8,611 | 8,603 | 8,592 | 8,632 |
| **East Position** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Available Market Purchases** | 500 | 500 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West** | | | | | | | | | | |
| Coal | 133 | 133 | 133 | 133 | 133 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 74 | 72 | 70 | 67 | 65 | 63 | 61 | 59 | 57 | 54 |
| Solar | 69 | 67 | 65 | 62 | 60 | 58 | 52 | 50 | 48 | 46 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 232 | 226 | 215 | 209 | 200 | 194 | 187 | 179 | 174 | 170 |
| Demand Response | 60 | 59 | 58 | 57 | 57 | 56 | 55 | 54 | 54 | 53 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 274 | 1,440 | 1,361 | 1,096 | 902 | 631 | 476 | 421 | 380 | 277 |
| **West Existing Resources** | **2,271** | **3,426** | **3,330** | **3,054** | **2,846** | **2,431** | **2,260** | **2,192** | **2,141** | **2,028** |
| Load | 3,778 | 3,812 | 3,905 | 3,967 | 4,032 | 4,103 | 4,239 | 4,255 | 4,288 | 4,376 |
| Distributed Generation | (49) | (54) | (75) | (99) | (124) | (152) | (182) | (213) | (132) | (148) |
| Energy Efficiency | (67) | (94) | (135) | (178) | (220) | (263) | (318) | (359) | (389) | (431) |
| **West Total obligation** | **3,662** | **3,664** | **3,695** | **3,690** | **3,688** | **3,688** | **3,738** | **3,684** | **3,767** | **3,798** |
| **Planning Reserve Margin (14.4%)** | 527 | 528 | 532 | 531 | 531 | 531 | 538 | 530 | 542 | 547 |
| **West Obligation + Reserves** | 4,189 | 4,192 | 4,227 | 4,222 | 4,219 | 4,219 | 4,277 | 4,214 | 4,309 | 4,345 |
| **West Position** | (1,918) | (766) | (898) | (1,168) | (1,373) | (1,788) | (2,016) | (2,022) | (2,168) | (2,317) |
| **Available Market Purchases** | 2,603 | 2,603 | 2,603 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **System** | | | | | | | | | | |
| **Total Resources** | 10,849 | 11,859 | 11,782 | 11,533 | 11,349 | 10,971 | 10,871 | 10,795 | 10,734 | 10,660 |
| **Obligation** | 11,160 | 11,036 | 11,084 | 11,102 | 11,121 | 11,153 | 11,265 | 11,203 | 11,278 | 11,343 |
| **Planning Reserves (14.4%)** | 1,607 | 1,589 | 1,596 | 1,599 | 1,601 | 1,606 | 1,622 | 1,613 | 1,624 | 1,633 |
| **Obligation + Reserves** | 12,767 | 12,625 | 12,680 | 12,701 | 12,723 | 12,759 | 12,887 | 12,817 | 12,902 | 12,977 |
| **System Position** | (1,918) | (766) | (898) | (1,168) | (1,373) | (1,788) | (2,016) | (2,022) | (2,168) | (2,317) |
| **Available Market Purchases** | 3,103 | 3,103 | 3,103 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Uncommitted FOTs to meet remaining Need** | 1,918 | 766 | 898 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Surplus/(Deficit)** | 0 | 0 | 0 | (1,168) | (1,373) | (1,788) | (2,016) | (2,022) | (2,168) | (2,317) |

## Table 6.14 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,432 | 2,432 | 2,432 |
| Gas | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,322 | 3,322 | 3,322 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 437 | 421 | 404 | 387 | 371 | 355 | 308 | 293 | 278 | 263 | 249 |
| Solar | 392 | 381 | 340 | 329 | 319 | 308 | 297 | 286 | 276 | 243 | 233 |
| Other Renewable | 33 | 32 | 31 | 12 | 11 | 10 | 10 | 9 | 9 | 8 | 0 |
| Storage | 804 | 788 | 773 | 759 | 744 | 728 | 714 | 699 | 684 | 668 | 654 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 291 | 269 | 221 | 212 | 203 | 192 | 184 | 176 | 169 | 162 | 155 |
| Demand Response | 422 | 401 | 402 | 398 | 400 | 406 | 398 | 375 | 376 | 389 | 351 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (161) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **8,690** | **8,763** | **8,643** | **8,569** | **8,519** | **8,472** | **8,383** | **8,310** | **7,622** | **7,564** | **7,472** |
| Load | 8,893 | 9,150 | 9,349 | 9,567 | 9,774 | 9,993 | 10,214 | 10,478 | 10,693 | 10,891 | 11,097 |
| Distributed Generation | (385) | (415) | (445) | (474) | (503) | (529) | (557) | (584) | (609) | (635) | (660) |
| Energy Efficiency | (911) | (983) | (1,112) | (1,227) | (1,325) | (1,407) | (1,501) | (1,482) | (1,547) | (1,570) | (1,588) |
| **East Total obligation** | **7,596** | **7,752** | **7,792** | **7,865** | **7,946** | **8,057** | **8,156** | **8,413** | **8,536** | **8,686** | **8,848** |
| **Planning Reserve Margin (14.4%)** | 1,094 | 1,116 | 1,122 | 1,133 | 1,144 | 1,160 | 1,174 | 1,211 | 1,229 | 1,251 | 1,274 |
| **East Obligation + Reserves** | 8,690 | 8,869 | 8,914 | 8,998 | 9,090 | 9,217 | 9,330 | 9,624 | 9,766 | 9,937 | 10,123 |
| **East Position** | 0 | (105) | (271) | (429) | (571) | (745) | (947) | (1,314) | (2,144) | (2,373) | (2,650) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 52 | 50 | 48 | 46 | 44 | 41 | 39 | 37 | 35 | 33 | 31 |
| Solar | 45 | 43 | 41 | 39 | 37 | 35 | 13 | 12 | 11 | 11 | 10 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 165 | 160 | 142 | 138 | 132 | 128 | 124 | 120 | 101 | 97 | 95 |
| Demand Response | 52 | 51 | 51 | 50 | 49 | 48 | 48 | 47 | 46 | 45 | 44 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 161 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **1,902** | **1,731** | **1,708** | **1,700** | **1,689** | **1,681** | **1,651** | **1,644** | **1,621** | **1,613** | **1,608** |
| Load | 4,475 | 4,577 | 4,692 | 4,807 | 4,927 | 5,049 | 5,173 | 5,376 | 5,430 | 5,553 | 5,680 |
| Distributed Generation | (163) | (177) | (192) | (206) | (221) | (234) | (249) | (263) | (277) | (290) | (304) |
| New Energy Efficiency | (471) | (515) | (571) | (603) | (634) | (661) | (691) | (774) | (591) | (599) | (612) |
| **West Total obligation** | **3,841** | **3,885** | **3,929** | **3,998** | **4,073** | **4,154** | **4,233** | **4,340** | **4,562** | **4,663** | **4,764** |
| **Planning Reserve Margin (14.4%)** | 553 | 559 | 566 | 576 | 586 | 598 | 609 | 625 | 657 | 671 | 686 |
| **West Obligation + Reserves** | 4,394 | 4,444 | 4,495 | 4,574 | 4,659 | 4,752 | 4,842 | 4,965 | 5,219 | 5,334 | 5,450 |
| **West Position** | (2,492) | (2,713) | (2,787) | (2,874) | (2,970) | (3,072) | (3,191) | (3,321) | (3,598) | (3,721) | (3,842) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **System** | | | | | | | | | | | |
| **Total Resources** | 10,592 | 10,494 | 10,351 | 10,269 | 10,209 | 10,152 | 10,034 | 9,954 | 9,243 | 9,178 | 9,080 |
| **Obligation** | 11,438 | 11,637 | 11,721 | 11,863 | 12,019 | 12,211 | 12,388 | 12,753 | 13,099 | 13,349 | 13,612 |
| **Planning Reserves (14.4%)** | 1,647 | 1,676 | 1,688 | 1,708 | 1,731 | 1,758 | 1,784 | 1,836 | 1,886 | 1,922 | 1,960 |
| **Obligation + Reserves** | 13,085 | 13,313 | 13,409 | 13,572 | 13,750 | 13,969 | 14,172 | 14,589 | 14,985 | 15,272 | 15,573 |
| **System Position** | (2,492) | (2,818) | (3,058) | (3,303) | (3,541) | (3,817) | (4,138) | (4,635) | (5,742) | (6,094) | (6,493) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Uncommitted FOTs to meet remaining Need** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Surplus/(Deficit)** | (2,492) | (2,818) | (3,058) | (3,303) | (3,541) | (3,817) | (4,138) | (4,635) | (5,742) | (6,094) | (6,493) |

# Table 6.15 – Winter Peak System Capacity Loads and Resources without Resource Additions

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 4,147 | 3,734 | 3,734 | 3,499 | 3,185 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 |
| Gas | 3,003 | 3,334 | 3,334 | 3,335 | 3,526 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 1,837 | 1,957 | 1,892 | 1,829 | 1,766 | 1,657 | 1,523 | 1,463 | 1,404 | 1,346 |
| Solar | 38 | 104 | 101 | 98 | 95 | 92 | 89 | 85 | 82 | 79 |
| Other Renewable | 41 | 39 | 38 | 37 | 35 | 34 | 33 | 32 | 30 | 29 |
| Storage | 1 | 621 | 606 | 591 | 576 | 561 | 546 | 531 | 516 | 500 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 186 | 181 | 176 | 171 | 166 | 161 | 156 | 149 | 140 | 124 |
| Demand Response | 119 | 118 | 118 | 128 | 129 | 128 | 121 | 120 | 128 | 127 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (1,600) | (1,600) | (1,600) | (1,600) | (1,600) | (1,600) | (1,600) | (1,585) | (1,353) | (1,118) |
| **East Existing Resources** | **7,804** | **8,523** | **8,433** | **8,120** | **7,911** | **7,608** | **7,442** | **7,369** | **7,522** | **7,662** |
| Load | 5,898 | 5,911 | 6,036 | 6,164 | 6,278 | 6,408 | 6,569 | 6,706 | 6,899 | 7,084 |
| Distributed Generation | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| Energy Efficiency | (75) | (118) | (157) | (197) | (239) | (283) | (331) | (388) | (450) | (513) |
| **East Total obligation** | **5,821** | **5,790** | **5,876** | **5,963** | **6,033** | **6,119** | **6,231** | **6,309** | **6,440** | **6,560** |
| **Planning Reserve Margin (16.8%)** | 978 | 973 | 987 | 1,002 | 1,014 | 1,028 | 1,047 | 1,060 | 1,082 | 1,102 |
| **East Obligation + Reserves** | 6,799 | 6,763 | 6,863 | 6,964 | 7,047 | 7,147 | 7,278 | 7,369 | 7,522 | 7,662 |
| **East Position** | 1,005 | 1,760 | 1,570 | 1,156 | 864 | 461 | 164 | 0 | 0 | 0 |
| **Available Market Purchases** | 500 | 500 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West** | | | | | | | | | | |
| Coal | 147 | 147 | 147 | 147 | 147 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 64 | 62 | 59 | 57 | 55 | 53 | 51 | 49 | 47 | 45 |
| Solar | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 70 | 69 | 62 | 61 | 58 | 57 | 57 | 56 | 56 | 56 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,585 | 1,353 | 1,118 |
| **West Existing Resources** | **3,345** | **3,342** | **3,333** | **3,330** | **3,325** | **3,174** | **3,171** | **3,153** | **2,919** | **2,679** |
| Load | 3,511 | 3,571 | 3,640 | 3,701 | 3,741 | 3,805 | 3,904 | 3,981 | 4,068 | 4,160 |
| Distributed Generation | (0) | (0) | (1) | (1) | (1) | (1) | (1) | (2) | (2) | (2) |
| Energy Efficiency | (52) | (65) | (118) | (173) | (229) | (286) | (345) | (401) | (457) | (511) |
| **West Total obligation** | **3,459** | **3,506** | **3,521** | **3,527** | **3,511** | **3,517** | **3,558** | **3,578** | **3,609** | **3,647** |
| **Planning Reserve Margin (16.8%)** | 581 | 589 | 591 | 593 | 590 | 591 | 598 | 601 | 606 | 613 |
| **West Obligation + Reserves** | 4,041 | 4,095 | 4,112 | 4,120 | 4,101 | 4,108 | 4,156 | 4,180 | 4,215 | 4,259 |
| **West Position** | (696) | (753) | (780) | (790) | (776) | (934) | (985) | (1,027) | (1,297) | (1,581) |
| **Available Market Purchases** | 2,603 | 2,603 | 2,603 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **System** | | | | | | | | | | |
| **Total Resources** | 11,149 | 11,865 | 11,766 | 11,450 | 11,235 | 10,783 | 10,613 | 10,522 | 10,441 | 10,341 |
| **Obligation** | 9,281 | 9,296 | 9,397 | 9,490 | 9,544 | 9,636 | 9,789 | 9,888 | 10,049 | 10,207 |
| **Planning Reserves (16.8%)** | 1,336 | 1,339 | 1,353 | 1,367 | 1,374 | 1,388 | 1,410 | 1,424 | 1,447 | 1,470 |
| **Obligation + Reserves** | 10,617 | 10,635 | 10,750 | 10,857 | 10,918 | 11,024 | 11,199 | 11,312 | 11,497 | 11,677 |
| **System Position** | 532 | 1,230 | 1,016 | 594 | 317 | (241) | (586) | (789) | (1,056) | (1,336) |
| **Available Market Purchases** | 3,103 | 3,103 | 3,103 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Uncommitted FOTs to meet remaining Need** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Surplus/(Deficit)** | 532 | 1,230 | 1,016 | 594 | 317 | (241) | (586) | (789) | (1,056) | (1,336) |

## Table 6.15 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 2,503 | 2,503 | 2,503 |
| Gas | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,378 | 3,378 | 3,378 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 1,285 | 1,226 | 1,168 | 1,107 | 1,049 | 990 | 850 | 797 | 744 | 689 | 636 |
| Solar | 76 | 73 | 70 | 67 | 64 | 61 | 58 | 55 | 52 | 42 | 39 |
| Other Renewable | 28 | 26 | 25 | 9 | 8 | 8 | 7 | 7 | 6 | 6 | 0 |
| Storage | 485 | 470 | 455 | 440 | 425 | 410 | 395 | 379 | 365 | 350 | 334 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 120 | 112 | 99 | 94 | 90 | 86 | 82 | 78 | 75 | 71 | 67 |
| Demand Response | 128 | 117 | 121 | 121 | 125 | 132 | 129 | 117 | 121 | 132 | 109 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (919) | (674) | (414) | (137) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **7,778** | **7,925** | **8,097** | **8,275** | **8,336** | **8,262** | **8,096** | **8,008** | **7,276** | **7,204** | **7,101** |
| Load | 7,248 | 7,421 | 7,645 | 7,863 | 8,087 | 8,287 | 8,466 | 8,705 | 8,909 | 9,134 | 9,224 |
| Distributed Generation | (11) | (11) | (12) | (13) | (13) | (14) | (14) | (14) | (15) | (15) | (16) |
| Energy Efficiency | (579) | (624) | (700) | (766) | (826) | (886) | (954) | (973) | (1,022) | (1,049) | (1,077) |
| **East Total obligation** | **6,659** | **6,786** | **6,932** | **7,084** | **7,248** | **7,387** | **7,498** | **7,717** | **7,872** | **8,070** | **8,131** |
| **Planning Reserve Margin (16.8%)** | 959 | 977 | 998 | 1,020 | 1,044 | 1,064 | 1,080 | 1,111 | 1,134 | 1,162 | 1,171 |
| **East Obligation + Reserves** | 7,618 | 7,763 | 7,931 | 8,105 | 8,292 | 8,451 | 8,578 | 8,828 | 9,005 | 9,232 | 9,302 |
| **East Position** | 160 | 163 | 166 | 170 | 44 | (189) | (482) | (820) | (1,729) | (2,028) | (2,201) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 42 | 40 | 38 | 36 | 34 | 32 | 30 | 28 | 25 | 23 | 21 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 55 | 54 | 53 | 53 | 51 | 51 | 50 | 50 | 50 | 49 | 49 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 919 | 674 | 414 | 137 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **2,478** | **2,229** | **1,967** | **1,687** | **1,546** | **1,544** | **1,541** | **1,539** | **1,536** | **1,534** | **1,531** |
| Load | 4,232 | 4,334 | 4,471 | 4,605 | 4,720 | 4,832 | 4,959 | 5,143 | 5,253 | 5,374 | 5,365 |
| Distributed Generation | (2) | (3) | (3) | (3) | (3) | (3) | (3) | (4) | (4) | (4) | (4) |
| Energy Efficiency | (568) | (624) | (668) | (714) | (760) | (819) | (858) | (900) | (786) | (803) | (826) |
| **West Total obligation** | **3,662** | **3,707** | **3,800** | **3,888** | **3,957** | **4,010** | **4,097** | **4,239** | **4,463** | **4,567** | **4,535** |
| **Planning Reserve Margin (16.8%)** | 615 | 623 | 638 | 653 | 665 | 674 | 688 | 712 | 750 | 767 | 762 |
| **West Obligation + Reserves** | 4,277 | 4,330 | 4,438 | 4,541 | 4,622 | 4,684 | 4,786 | 4,952 | 5,212 | 5,334 | 5,297 |
| **West Position** | (1,799) | (2,100) | (2,471) | (2,854) | (3,075) | (3,140) | (3,245) | (3,413) | (3,676) | (3,801) | (3,766) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **System** | | | | | | | | | | | |
| **Total Resources** | 10,255 | 10,155 | 10,064 | 9,962 | 9,882 | 9,806 | 9,637 | 9,547 | 8,812 | 8,737 | 8,632 |
| **Obligation** | 10,321 | 10,493 | 10,732 | 10,973 | 11,205 | 11,398 | 11,596 | 11,957 | 12,334 | 12,637 | 12,666 |
| **Planning Reserves (16.8%)** | 1,486 | 1,511 | 1,545 | 1,580 | 1,614 | 1,641 | 1,670 | 1,722 | 1,776 | 1,820 | 1,824 |
| **Obligation + Reserves** | 11,807 | 12,003 | 12,278 | 12,553 | 12,819 | 13,039 | 13,265 | 13,678 | 14,110 | 14,456 | 14,490 |
| **System Position** | (1,552) | (1,849) | (2,214) | (2,591) | (2,937) | (3,233) | (3,628) | (4,132) | (5,298) | (5,719) | (5,858) |
| **Available Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Uncommitted FOTs to meet remaining Need** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Surplus/(Deficit)** | (1,552) | (1,849) | (2,214) | (2,591) | (2,937) | (3,233) | (3,628) | (4,132) | (5,298) | (5,719) | (5,858) |

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used

to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7 (Resource Options).

**Figure 6.4 – Summer System Capacity Position Trend**

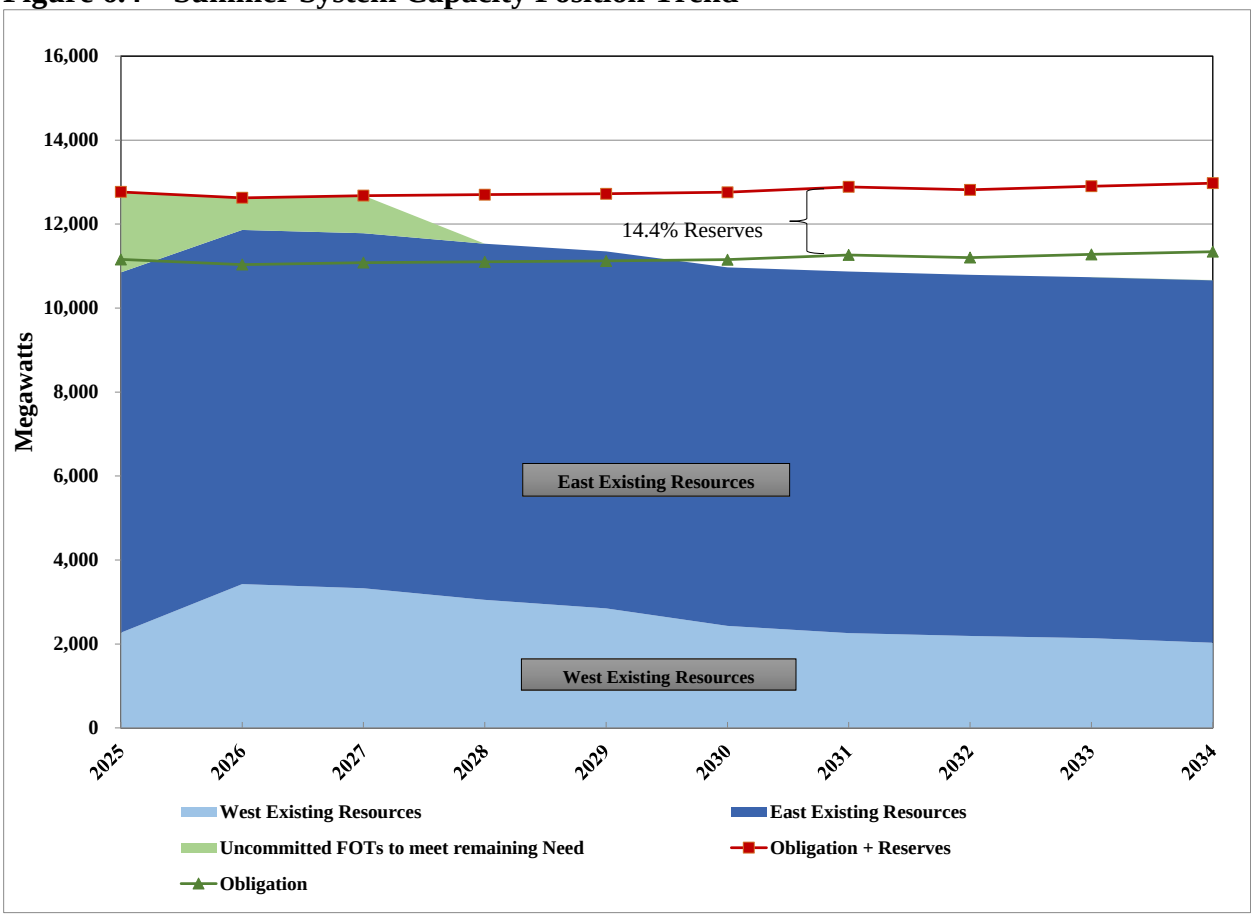


**Figure 6.5 – Winter System Capacity Position Trend**

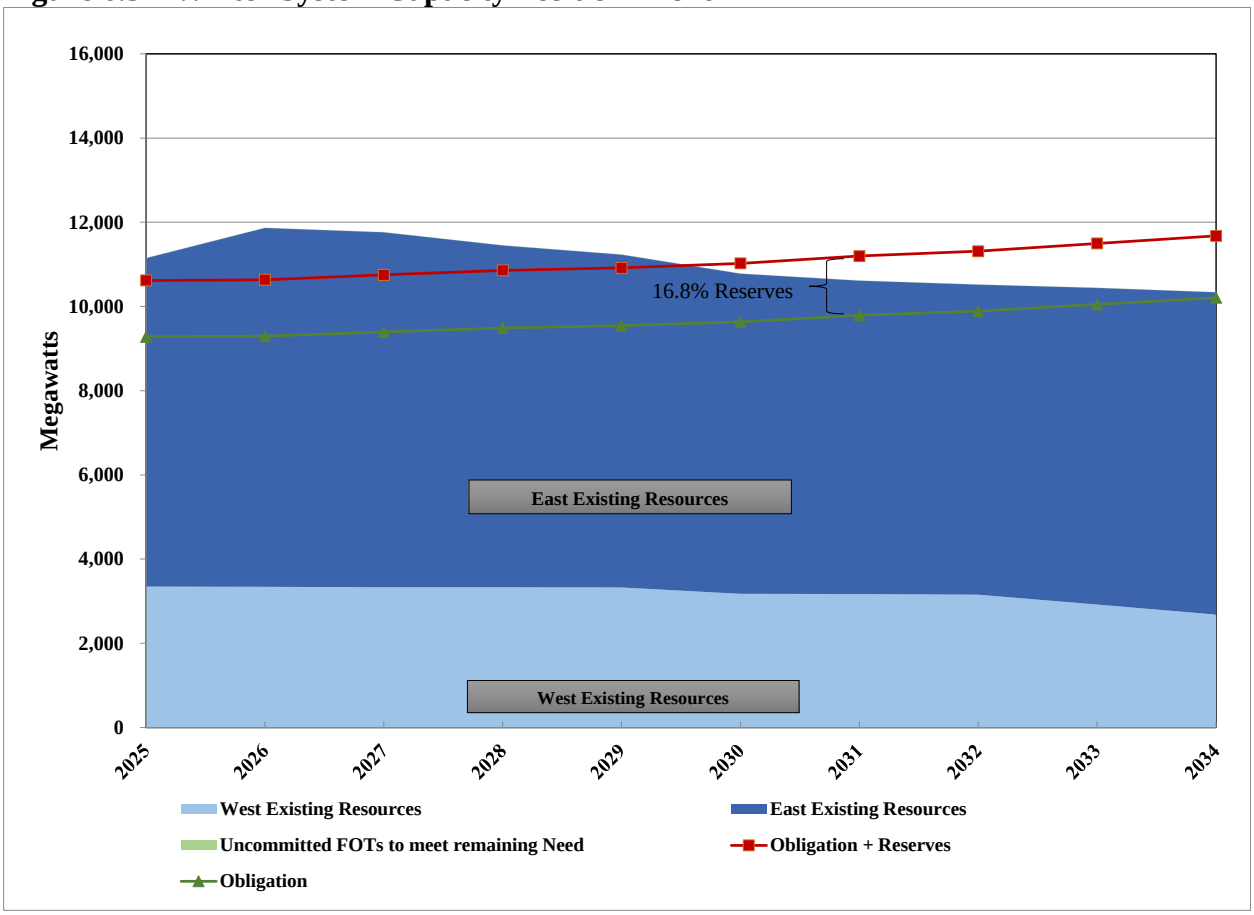


**Figure 6.6 – East Summer Capacity Position Trend**

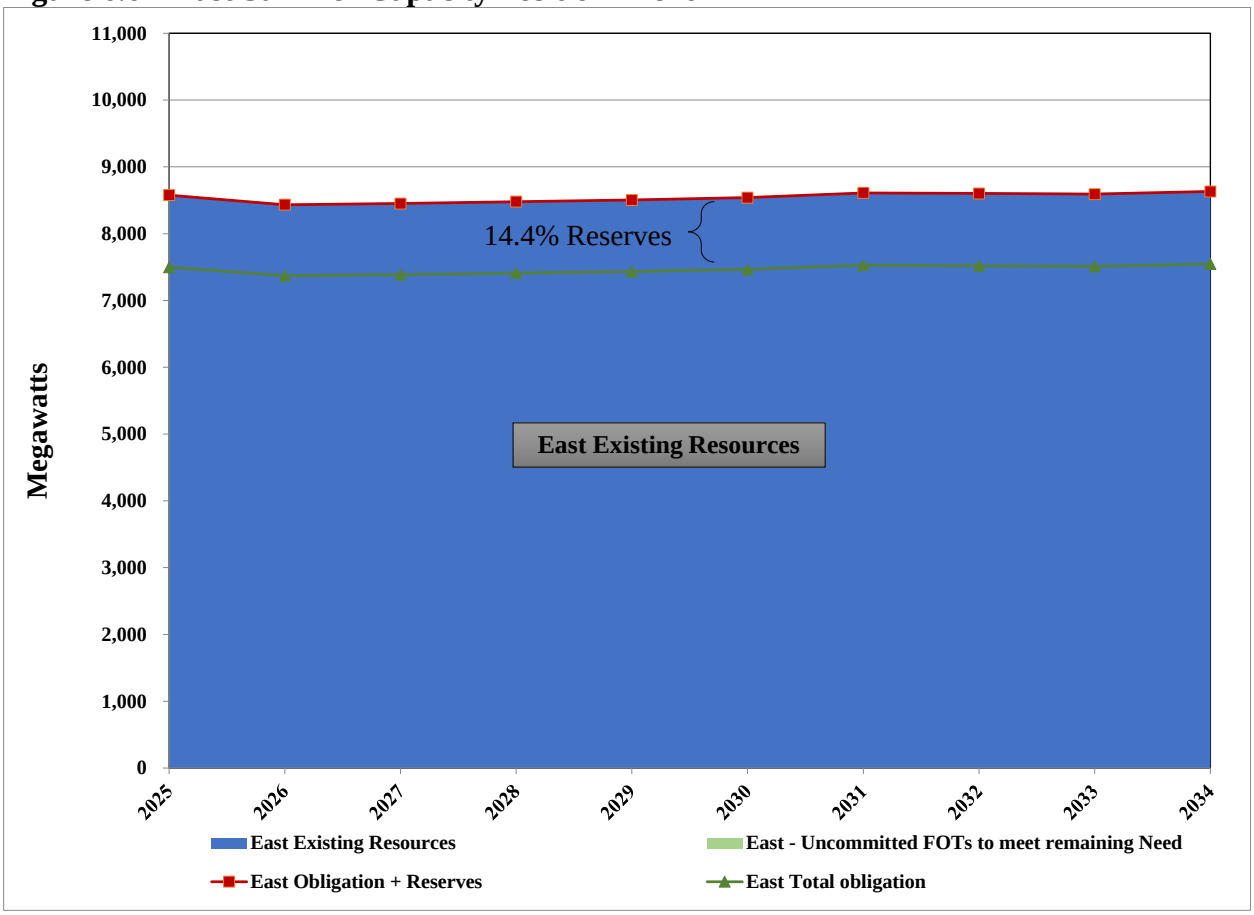
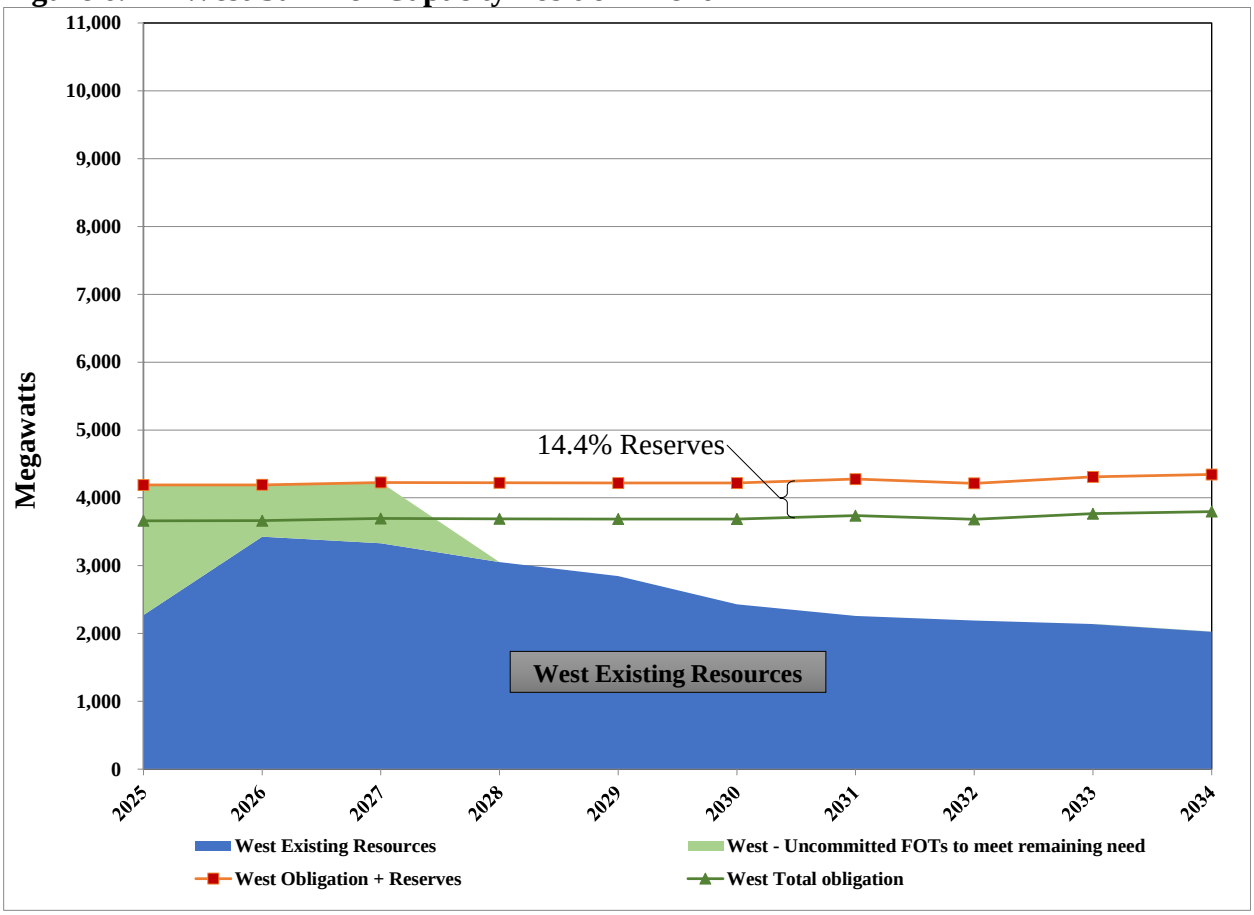


**Figure 6.7 – West Summer Capacity Position Trend**



# CHAPTER 7 – RESOURCE OPTIONS

## CHAPTER HIGHLIGHTS

- PacifiCorp's resource attributes and costs for future generation resource options reflect updated information, based on assumptions from the National Renewable Energy Laboratory's 2024 Annual Technology Baseline to the extent data was available.[1]
- In addition to utility-scale resources (generally 200 megawatts (MW) or more), the 2025 IRP includes small-scale (20 MW) wind, solar, and biodiesel peaking options. These small-scale resource options are assumed to be sited in relative proximity to load, such that they do not require significant transmission system upgrades.
- Renewable resource generation profiles have been updated and expanded to include more proxy resource locations as well as distinct profiles for utility-scale and small-scale wind resources, rather than one generation profile per state as in the 2023 IRP. This update extends to online and contracted resources, as well as proxy resource options, and includes expanded historical data for use with stochastic analysis.
- Options for utility-scale lithium-ion batteries (20 MW and 200 MW options), gravity energy storage systems, pumped hydro energy storage (PHES), thermal energy storage, one-hundred-hour iron-air storage, and adiabatic compressed air energy storage are included in this IRP. In a change from prior IRPs, hydrogen peaking resources are also treated as storage resources (rather than using pipelines and a market price for hydrogen). Hydrogen is electrolyzed using excess generation output and stored in either high-pressure tanks or underground caverns.
- PLEXOS endogenously models transmission upgrades, allowing for increases to transfer limits and resource interconnection. Where applicable, upgrades are restricted until all pre-requisites are in place.
- PacifiCorp continues to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

## Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

[1] https://atb.nrel.gov/electricity/2024/index

## Supply-Side Resources

The list of supply-side resource options reflects the expected realities evidenced through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input. The process began with the list of major generating resources from the 2023 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[2] was used as much as possible to maintain consistency. Some of the terminology used in this chapter is from the ATB. A glossary of some of the terminology is provided below in Table 7.12 and a list of acronyms is provided in Table 7.13.

The supply-side resource options include the following technologies grouped by energy source. More information about each technology is provided in the "Resource Option Descriptions" section of this chapter. The terminology here matches that used in the supply-side resource table, although some may have been shortened per the acronym list in Table 7.13.

- Natural Gas
  - Internal Combustion Engines.
  - SCCT, Aero, & F-Frame.
  - CCCT, 1x1, & 2x1.
    - Adjustments for 95% Carbon Capture.
    - Adjustments for Brownfield Construction.
    - Adjustments for advanced technology innovation scenario ("Innovations far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases. For biopower technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages."[3])
- Hydrogen
  - Adjustments for 100% Hydrogen burning capability.
  - Adjustments for Hydrogen Storage.
  - Electrolyzer.
- Coal, Carbon Capture Retrofits at existing plants
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW all with 4-hour duration):
    - Adjustments for double duration (i.e., 8-hour duration).
    - Adjustments for co-location with other generating resources.
    - Adjustments for advanced technology innovation scenario.
  - Gravity Batteries.
  - Adiabatic Compressed Air Energy Storage (ACAES).
  - 100-Hour Iron Air Batteries.
  - PHES (single and double reservoirs).
  - Pumped Thermal.
- Solar

[2] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[3] https://atb.nrel.gov/electricity/2024/definitions#scenarios

    - Adjustments for advanced technology innovation scenario.
- Wind (various on-shore wind classes and off-shore class 12, as appropriate for PacifiCorp's service area)
    - Adjustments for advanced technology innovation scenario.
- Nuclear[4]
    - Small Modular Reactor.
        - Adjustments for adding thermal energy storage.
    - Large Light Water Reactor.
        - Adjustments for advanced technology innovation scenario (in addition to the earlier definition: "for nuclear technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.")
- Geothermal (near field enhanced geothermal system, binary)
    - Adjustments for advanced technology innovation scenario.

## Derivation of Resource Attributes

Once a basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table, which is used to develop inputs for IRP modeling:

- Annual Technology Baseline (ATB) prepared by the National Renewable Energy Laboratory (NREL).[5]
- U.S. Energy Information Administration (EIA) "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" ("EIA Report," both the 2024[6] and 2020[7] editions) prepared by Sargent and Lundy.
- Original equipment manufacturers capital and operation and maintenance estimates.
- Developer cost and performance estimates.
- Publicly available cost and performance estimates.
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes.
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.
- Additional references are provided in the Resource Option Descriptions section of this chapter.

[4] Nuclear technology is intentionally limited to years outside the 2-4 year action plan window. Nuclear resource assumptions were discussed in the 2025 IRP public input meeting series and stakeholder feedback,
See Appendix M, stakeholder feedback form #1 (Peter Gross).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

[5] https://atb.nrel.gov/electricty/2024/index.

[6] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the supply-side resource table are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers, and original equipment manufacturers (OEM's). The 2024 ATB with its numerous references and the 2024 EIA Report was used for:

- Natural Gas
  - SCCT (Aero).
  - CCCT (1x1 & 2x1).
    - Adjustments for 95% Carbon Capture.
    - Adjustments for advanced technology innovation scenario.
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW, 4-hour duration).
    - Adjustments for double duration.
    - Adjustments for co-location.
    - Adjustments for advanced technology innovation scenario.
  - PHES (single and double reservoirs).
- Solar
  - Adjustments for advanced technology innovation scenario.
- Wind
  - Adjustments for advanced technology innovation scenario.
- Nuclear
  - Small Modular Reactor.
  - Large Light Water Reactor.
  - Adjustments for advanced technology innovation scenario.
- Geothermal (near field enhanced geothermal system, binary)
  - Adjustments for advanced technology innovation scenario.

The 2020 EIA Report provided the Internal Combustion Engines (ICE) data because no ICE option was included in the 2024 EIA report. The ICE option was included to address Oregon requirements for small-scale resources under 20 MW. Although the ICE option consists of 4 x 5.6 MW engines at ISO conditions, it is assumed that the engines, if not derated due to altitude or other factors, can be curtailed to meet the 20 MW threshold.

The brownfield cost adjustment was developed based on prior IRP estimates.

Hydrogen capable resource data is based on the following:[8]

- Adjustments for 100% hydrogen burning capability are based on conversations with OEMs and industry experts and the report "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems."[9] A 15% cost adder for new gas turbines indicated by Table 3 in the report was corroborated by OEMs and other industry experts.

[8] The option of hydrogen as an alternative fuel, including electrolyzer cost and performance, was discussed in the course of the 2025 IRP public input meeting series. For specific recommendations and PacifiCorp's response, see Appendix M, stakeholder feedback form #23 (NP Energy, LLC)

[9] Simon Oberg, Mikael Odenberger, Filip Johnsson "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems," Division of Energy Technology, Chalmers University of Technology, 412 96, Gothenburg, Sweden, https://www.sciencedirect.com/science/article/pii/S0360319921039768

- Adjustments for hydrogen storage are based on information in the U.S. Department of Energy (DOE) reports: "Pathways to Commercial Liftoff: Clean Hydrogen"[10] (Clean Hydrogen Liftoff report), "2022 Grid Energy Storage Technology Cost and Performance Assessment,"[11] and the Hydrogen and Fuel Cell Technologies Office's "Multi-Year Program Plan."[12]
- Electrolyzer costs are based on the DOE report "Hydrogen Production Cost from PEM Electrolysis – 2019,"[13] and the NREL report "Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers."

Data for "Carbon Capture Retrofits at existing coal plants" is based on adjustments made to incorporate capital and operational costs of emission control technologies (SCR and FGD) needed to scrub flue gas prior to the carbon capture technology, and adjustments made to account for economies of scale.

Gravity Batteries costs were escalated from the 2023 IRP.

Adiabatic Compressed Air Energy Storage (ACAES) were originally escalated from the 2023 IRP which used data provided by Renewable Energy Storage Company (RESC) but later updated based on input from Hydrostor.

100-Hour Iron Air Battery data is based on information provided by Form Energy.[14]

Pumped Thermal energy storage is based on integrated thermal storage for nuclear, but with a resistive heater for energy storage.

Data for "Adjustments for adding thermal energy storage to nuclear plants" represents thermal energy storage and only stores energy from the heat of the reactor, not from a resistive heater.
The following costs were excluded from the cost estimates provided by the referenced sources, but were added by the Company as appropriate, using confidential data specific to the Company's business practices:[15]

- Allowance for Funds Used During Construction (AFUDC).
- Capital Surcharge.
- Escalation.
- Property taxes.

Interconnection costs and sales tax are included in the PLEXOS modeling depending on the locational node in which each technology is being considered.

[10] https://liftoff.energy.gov/
[11] https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf
[12] https://www.energy.gov/sites/default/files/2024-05/hfto-mypp-2024.pdf
[13] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master
[14] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[15] Additional cost considerations were the subject of discussion and feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #24 (NP Energy, LLC).

## Wind and Solar Generation Profiles

For the 2025 IRP, PacifiCorp has updated the wind and solar generation profiles for both existing resources and proxy resource options. PacifiCorp provided the location and expected generation levels for existing and contracted resources to a consultant, Hendrickson Renewables, and received back an hourly generation profile for 2006-2023 that reflects expected performance under historical weather conditions.

For existing resources, results were tuned to recent historical actual generation levels, while resources that are not yet operating were tuned to forecasted output. For wind, hourly generation is based on hourly wind speeds and air density from the ERA5 reanalysis dataset, with scaling and adjustments to represent project-specific power curves and expected output.[16] For solar, hourly solar irradiance and weather data was extracted from a Vaisala satellite irradiance dataset[17] and configured in a $PV_{syst}$ model[18] that was tuned to correspond to actual or forecasted output.

For proxy resources, PacifiCorp identified locations across its system, and Hendrickson Renewables determined the expected output of the equipment represented in NREL's ATB, which was used to develop cost inputs. In the 2023 IRP, PacifiCorp used one wind and solar profile for each of its five largest state jurisdictions (excluding California). For the 2025 IRP, wind and solar profiles have been developed which to correspond to thirteen different transmission areas spread across PacifiCorp's system. To account for technological differences that impact generation output, generation profiles were also developed for five small-scale wind profiles for the west side of the system, along with an off-shore wind profile for the potential lease area near Brookings.[19]

For many years, PacifiCorp has used a chaotic normal load forecast to account for the range of load conditions experienced. For each month of the year, the chaotic normal load forecast is derived from the most representative historical month from recent history (currently 2013-2022). The pattern of load in each of the selected months from history is reflected in every year of the forecast, with adjustments to account for the rotation of calendar days and weekdays from year to year, as well as for forecasted changes in load over time. As a result, every day of PacifiCorp's load forecast is tied to a specific day in history. For the 2025 IRP, the normalized wind and solar output modeled in PLEXOS is drawn from the same historical day as the load forecast. The result is a generation profile specific to each of the years of the IRP forecast (2025-2045) that inherently represents the correlation between renewable generation and load. The expanded historical generation data set developed for the 2025 IRP also enables stochastic analysis that captures the relationship between renewable generation and load in each of the historical years (2006-2023).

## Natrium Demonstration Project

PacifiCorp's 2025 IRP includes the Natrium® advanced nuclear demonstration project: an 840 megawatt thermal pool-type sodium fast reactor that contains a compact and simple safety envelope and a molten salt energy storage system which enables the plant to vary its supply of energy to the grid, up to 500 megawatts electric net, providing both firm and flexible emissions-free energy. The reactor operates near atmospheric pressure, circulating sodium through its core

[16] European Centre for Medium-Range Weather Forecasts.https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5
[17] Vaisala. https://www.vaisala.com/
[18] $PV_{syst}$. https://www.pvsyst.com/
[19] Bureau of Ocean Energy Management. https://www.boem.gov/renewable-energy/state-activities/Oregon

with pumps. The design includes reliable inherent and passive safety features including near atmospheric operating pressures, always-on passive air cooling and inherent reactivity feedback.

At this time, the specific cost and performance assumptions for the Natrium® advanced nuclear demonstration project are confidential and are not summarized in the supply-side resource table. TerraPower and PacifiCorp remain committed to bringing the Natrium technology to market to enhance the company's ability to serve its customers, meet growing demand and ensure a reliable and resilient energy future. PacifiCorp is also committed to protecting customers from first-of-a-kind (FOAK) technology risk and FOAK program and construction costs. The Company is implementing an innovative commercial energy acquisition structure that allows Natrium benefits to flow to customers while ensuring those customers are not burdened with FOAK technology cost and risk. This commercial structure is in the final stages of development and the details are confidential at this time.

The Natrium advanced nuclear demonstration project has been named Kemmerer Power Station Unit 1 (KU1) which is planned to be built near the Naughton Power Plant. KU1 is currently in the design and licensing phase. TerraPower submitted the Construction Permit Application to the US Nuclear Regulatory Commission (US NRC) in March 2024. The US NRC has published their review schedule and anticipates the Preliminary Safety Analysis Report and Environmental Report to be approved by August 2026, and the Construction Permit Application to be approved by December 2026. This approval will allow the beginning of construction of the Nuclear Island. An Operating License is also required. TerraPower anticipates the Operating License Application to be submitted in September 2027 and achieving commercial operations the fall of 2031.

On June 10, 2024, TerraPower broke ground for the Natrium reactor demonstration project with construction of the sodium test and fill facility commencing first. On January 14, 2025, the State of Wyoming Industrial Siting Council (ISC) approved TerraPower's permit for construction and operational activities on the Natrium plant that are not under jurisdiction of the US NRC. This approval allows for the construction of non-nuclear facilities, including the energy island portion of the Natrium plant that houses the molten salt energy storage tanks and turbines.

## Resource Options and Attributes

Table 7.2 through Table 7.11 report characteristics, attributes and costs for resource options considered in the 2025 IRP. Unlike previous IRP's the supply-side resource table does not list multiple versions of the same technology for various altitudes. Instead, the location adjustments from Appendix A and B of the 2024 EIA[20] report are applied in PLEXOS. Total resource cost attributes for supply-side resource options are based on estimates of the first-year, real-levelized

[20] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

costs for resources, stated in June 2024 dollars.[21,22] Table 7.1 provides a listing of these ten tables for convenience.

**Table 7.1 – Supply-Side Resource Option Tables**

| | **Characteristics and Costs** | **Operating Characteristics and Environmental Data** |
|---|---|---|
| Thermal | Table 7.2 | Table 7.4 |
| Non-Thermal and Storage | Table 7.3 | Table 7.5 |
| | **Additional Attributes and Fixed O&M** | **Variable O&M, Total Cost and Credits** |
| Thermal | Table 7.6 | Table 7.9 |
| Non-Thermal | Table 7.7 | Table 7.10 |
| Storage | Table 7.8 | Table 7.11 |

A Glossary of Terms and a Glossary of Acronyms from the supply-side resource table is summarized in Table 7.12 and Table 7.13.

[21] Supply-side resource attributes were discussed throughout the 2025 public input meeting series and generated stakeholder feedback forms inquiries. 2028 was determined to be the appropriate earliest commercial online year for most proxy resource options. However, PacifiCorp does not preclude the possibility of achieving specific (non-proxy) projects on an earlier timeline outside of the IRP.
See Appendix M, stakeholder feedback form #7 (Renewable Northwest).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
[22] The supply-side resource table was made publicly available during the 2025 IRP public input meeting series and discussed extensively as it developed. https://www.pacificorp.com/energy/integrated-resource-plan/support.html

## Table 7.2 – 2025 Thermal Supply-Side Resources, Characteristics and Costs (2024$)

| | | Characteristics | | | | | | Costs | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource Description | Elevation (AFSL) | Net Capacity (MW) | Resource Availability Year | Total Implementation Time (yrs) | Commercial Operation Year | Asset Life (yrs) | Base Capital ($/kW) | Var O&M ($/MWh) | Fraction Var O&M Capitalized | Fraction Var O&M Adjusted by Capacity Changes | Fixed O&M ($/kW-yr) | Fraction Fixed O&M Capitalized | Demolition Cost ($/kW) |
| Biofuel | Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank | 0 | 20 | 2025 | 2.5 | 2027 | 30 | $2,131 | $6.93 | 74% | 91% | $42.82 | 3% | $14.59 |
| Natural Gas | SCCT Aero, with SCR | 0 | 50 | 2025 | 3.5 | 2028 | 40 | $2,613 | $7.40 | 87% | 98% | $12.42 | 3% | $32.46 |
| Natural Gas | SCCT Aero x4, with SCR | 0 | 211 | 2025 | 3.5 | 2028 | 40 | $1,789 | $5.92 | 87% | 98% | $9.93 | 3% | $32.46 |
| Natural Gas | SCCT Frame "F" x1, with SCR | 0 | 233 | 2025 | 5.0 | 2030 | 40 | $1,387 | $7.75 | 100% | 99% | $27.92 | 3% | $12.13 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR | 0 | 649 | 2025 | 5.0 | 2030 | 40 | $1,839 | $2.70 | 0% | 100% | $42.44 | 0% | $12.08 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR | 0 | 1,227 | 2025 | 5.0 | 2030 | 40 | $1,553 | $2.28 | 0% | 100% | $35.18 | 0% | $11.89 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 | 0 | 565 | 2025 | 5.0 | 2030 | +40 | $3,429 | $5.32 | 0% | 100% | $77.07 | 0% | $65.28 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 | 0 | 1085 | 2025 | 5.0 | 2030 | +40 | $2,846 | $4.83 | 0% | 100% | $62.99 | 0% | $65.08 |
| Natural Gas | Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction | 0 | 20 | 2025 | 2.5 | 2027 | 30 | $1,918 | $6.24 | 74% | 91% | $42.82 | 3% | $14.59 |
| Natural Gas | SCCT Aero, with SCR + Δ for CT Brownfield construction | 0 | 50 | 2025 | 3.5 | 2028 | 40 | $2,352 | $6.66 | 87% | 98% | $12.42 | 3% | $32.46 |
| Natural Gas | SCCT Aero x4, with SCR + Δ for CT Brownfield construction | 0 | 211 | 2025 | 3.5 | 2028 | 40 | $1,610 | $5.33 | 87% | 98% | $9.93 | 3% | $32.46 |
| Natural Gas | SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction | 0 | 233 | 2025 | 5.0 | 2030 | 40 | $1,248 | $6.98 | 100% | 99% | $27.92 | 3% | $12.13 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction | 0 | 649 | 2025 | 5.0 | 2030 | 40 | $1,655 | $2.43 | 0% | 100% | $42.44 | 0% | $12.08 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction | 0 | 1,227 | 2025 | 5.0 | 2030 | 40 | $1,398 | $2.05 | 0% | 100% | $35.18 | 0% | $11.89 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction | 0 | 565 | 2025 | 5.0 | 2030 | 40 | $3,086 | $4.78 | 0% | 100% | $77.07 | 0% | $65.28 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction | 0 | 1,085 | 2025 | 5.0 | 2030 | 40 | $2,561 | $4.34 | 0% | 100% | $62.99 | 0% | $65.08 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability | 0 | 233 | 2025 | 5.0 | 2030 | 40 | $1,595 | $8.91 | 100% | 99% | $27.92 | 3% | $13.95 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability | 0 | 649 | 2025 | 5.0 | 2030 | 40 | $2,115 | $3.11 | 0% | 100% | $42.44 | 0% | $13.89 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability | 0 | 1,227 | 2025 | 5.0 | 2030 | 40 | $1,786 | $2.62 | 0% | 100% | $35.18 | 0% | $13.67 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 0 | 233 | 2025 | 5.0 | 2030 | 40 | $2,586 | $8.18 | 100% | 99% | $35.12 | 3% | $27.13 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 0 | 649 | 2025 | 5.0 | 2030 | 40 | $3,038 | $3.13 | 0% | 100% | $49.64 | 0% | $27.08 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 0 | 1,227 | 2025 | 5.0 | 2030 | 40 | $2,752 | $2.70 | 0% | 100% | $42.38 | 0% | $26.89 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 0 | 233 | 2025 | 5.0 | 2030 | 40 | $2,098 | $8.32 | 100% | 99% | $40.78 | 3% | $27.13 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 0 | 649 | 2025 | 5.0 | 2030 | 40 | $2,550 | $3.27 | 0% | 100% | $55.30 | 0% | $27.08 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 0 | 1,227 | 2025 | 5.0 | 2030 | 40 | $2,264 | $2.85 | 0% | 100% | $48.04 | 0% | $26.89 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 | 0 | 649 | 2025 | 5.0 | 2030 | +40 | $1,832 | $2.68 | 0% | 100% | $41.33 | 0% | $12.08 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 | 0 | 1227 | 2025 | 5.0 | 2030 | +40 | $1,518 | $2.23 | 0% | 100% | $34.07 | 0% | $11.89 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS | 0 | 565 | 2025 | 5.0 | 2030 | +40 | $3,261 | $5.03 | 0% | 100% | $72.60 | 0% | $65.28 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS | 0 | 1085 | 2025 | 5.0 | 2030 | +40 | $2,637 | $4.49 | 0% | 100% | $57.74 | 0% | $65.08 |
| Hydrogen | Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day | 0 | -119 | 2025 | 5.0 | 2030 | 40 | $561 | $23.91 | +0% | 0.00 | $10.28 | 100% | $32.46 |
| Coal | CCS Dave Johnston 4 (costs on post retrofit basis) | 5,541 | -85 | 2027 | 5.0 | 2032 | 30 | $3,501 | $11.40 | 0% | 0% | $277.68 | 0% | $53.20 |
| Coal | CCS Hunter 1-3 (costs on post retrofit basis) | 6,429 | -297 | 2027 | 5.0 | 2032 | 30 | $2,951 | $9.73 | 0% | 0% | $235.36 | 0% | $53.20 |
| Coal | CCS Huntington 1&2 (costs on post retrofit basis) | 6,933 | -233 | 2027 | 5.0 | 2032 | 30 | $2,951 | $9.63 | 0% | 0% | $242.12 | 0% | $53.20 |
| Coal | CCS Jim Bridger 3&4 (costs on post retrofit basis) | 7,513 | -174 | 2025 | 5.0 | 2030 | 30 | $2,598 | $10.57 | 0% | 0% | $254.91 | 0% | $53.20 |
| Coal | CCS Wyodak (costs on post retrofit basis) | 4,448 | -69 | 2027 | 5.0 | 2032 | 30 | $3,504 | $11.69 | 0% | 0% | $309.51 | 0% | $53.20 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Moderate Technology Case | N/A | 600 | 2030 | 5.0 | 2035 | 60 | $9,662 | $9.74 | 0% | 0% | $97.42 | 0% | $17.00 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Advanced Technology Case | N/A | 600 | 2030 | 4.0 | 2034 | 60 | $6,368 | $8.74 | 0% | 0% | $84.53 | 0% | $12.00 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage | N/A | 750 | 2030 | 5.0 | 2035 | 60 | $10,628 | $10.72 | 0% | 0% | $107.16 | 0% | $17.00 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage | N/A | 750 | 2030 | 4.0 | 2034 | 60 | $7,005 | $9.61 | 0% | 0% | $92.98 | 0% | $12.00 |
| Nuclear | Large Light Water Reactor, Moderate Technology Case | N/A | 2,000 | 2030 | 7.0 | 2037 | 60 | $7,563 | $9.38 | 0% | 0% | $125.36 | 0% | $10.00 |
| Nuclear | Large Light Water Reactor, Advanced Technology Case | N/A | 2,000 | 2030 | 5.0 | 2035 | 60 | $6,265 | $7.88 | 0% | 0% | $90.26 | 0% | $9.00 |
| Geothermal | Near Field Enhanhanced Geothermal System (NF-EGS) Binary | N/A | 707 | 2025 | 3.0 | 2028 | 30 | $7,593 | included in FOM | 0% | 0% | $194.00 | 6% | $125.09 |
| Geothermal | Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case | N/A | 707 | 2025 | 3.0 | 2028 | 30 | $5,949 | included in FOM | 0% | 0% | $173.90 | 6% | $125.09 |

## Table 7.3 – 2025 Non-Thermal Supply-Side Resources, Characteristics and Costs (2024$)[23]

| | | Characteristics | | | | | | Costs | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource Description | Elevation (AFSL) | Net Capacity (MW) | Resource Availability Year | Total Implementation Time (yrs) | Commercial Operation Year | Asset Life (yrs) | Base Capital ($/kW) | Var O&M ($/MWh) | Fraction Var O&M Capitalized | Fraction Var O&M Adjusted by Capacity Changes | Fixed O&M ($/kW-yr) | Fraction Fixed O&M Capitalized | Demolition Cost ($/kW) |
| Storage[1] | Li-Ion, 4-hour, 20 MW | N/A | 20 | 2025 | 1.0 | 2026 | 20 | $1,748 | Included in FOM | 0% | 0% | $45.05 | 0% | $29.94 |
| Storage[1] | Li-Ion, 4-hour, 200 MW | N/A | 200 | 2025 | 2.0 | 2027 | 20 | $1,498 | Included in FOM | 0% | 0% | $38.77 | 0% | $25.66 |
| Storage[1] | Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW | N/A | 200 | 2025 | 2.0 | 2027 | 20 | $2,557 | Included in FOM | 0% | 0% | $69.78 | 0% | $46.19 |
| Storage[1] | Li-Ion, 4-hour, 1000 MW | N/A | 1,000 | 2025 | 3.0 | 2028 | 20 | $1,459 | Included in FOM | 0% | 0% | $36.92 | 0% | $25.66 |
| Storage | Gravity Battery, 4-hour, 1000 MW | N/A | 1,000 | 2025 | 3.0 | 2028 | 50 | $2,021 | Included in FOM | 0% | 0% | $50.51 | 0% | $0.19 |
| Storage | Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW | N/A | 1,000 | 2025 | 3.0 | 2028 | 50 | $3,006 | Included in FOM | 0% | 0% | $90.92 | 0% | $0.35 |
| Storage | Adiabatic CAES, 500 MW, 4000 MWh | N/A | 500 | 2025 | 3.0 | 2028 | 50 | $3,754 | $2.60 | 50% | 0% | $19.20 | 42% | $49.31 |
| Storage | 100-hour Iron Air | N/A | 200 | 2028 | 2.0 | 2030 | 20 | $2,730 | Included in FOM | 0% | 0% | $21.04 | 19% | $171.06 |
| Storage | Pumped Hydro, Two New Reservoirs, 4-hour | N/A | 400 | 2025 | 5.0 | 2030 | 100 | $2,984 | $0.58 | 0% | 0% | $20.20 | 45% | $149.21 |
| Storage | Pumped Hydro, Two New Reservoirs, 10-hour | N/A | 400 | 2025 | 5.0 | 2030 | 100 | $4,159 | $0.58 | 0% | 0% | $20.20 | 45% | $207.95 |
| Storage | Pumped Hydro, One New Reservoir, 4-hour | N/A | 400 | 2025 | 5.0 | 2030 | 100 | $2,883 | $0.58 | 0% | 0% | $20.20 | 45% | $144.16 |
| Storage | Pumped Hydro, One New Reservoir, 10-hour | N/A | 400 | 2025 | 5.0 | 2030 | 100 | $3,537 | $0.58 | 0% | 0% | $20.20 | 45% | $176.87 |
| Storage | Pumped Thermal Energy Storage, 10-hour | N/A | 100 | 2026 | 5.0 | 2031 | 60 | $6,174 | $0.70 | 0% | 0% | $2.00 | 0% | $60.00 |
| Storage | Pumped Thermal Energy Storage, 24-hour | N/A | 50 | 2026 | 5.0 | 2031 | 60 | $11,525 | $0.70 | 0% | 0% | $1.00 | 0% | $60.00 |
| Solar | PV, 20 MW, Class 1-10 | by location | 20 | 2025 | 3.0 | 2028 | 25 | $1,965 | included in FOM | 0% | 0% | $18.16 | 12% | $39.29 |
| Solar | PV, 200 MW, Class 1-10 | by location | 200 | 2025 | 3.0 | 2028 | 25 | $1,217 | included in FOM | 0% | 0% | $20.52 | 12% | $24.33 |
| Solar | PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case | by location | 20 | 2025 | 3.0 | 2028 | 25 | $1,832 | included in FOM | 0% | 0% | $17.24 | 12% | $37.33 |
| Solar | PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case | by location | 200 | 2025 | 3.0 | 2028 | 25 | $1,135 | included in FOM | 0% | 0% | $19.47 | 12% | $23.11 |
| Wind | Wind Class 1-10, 20 MW | by location | 20 | 2025 | 3.0 | 2028 | 30 | $2,555 | included in FOM | 0% | 0% | $38.79 | 35% | $63.57 |
| Wind | Wind Class 1-6, 200 MW | by location | 200 | 2025 | 5.0 | 2030 | 30 | $1,421 | included in FOM | 0% | 0% | $31.65 | 35% | $63.57 |
| Wind | Wind Class 7, 200 MW | by location | 200 | 2025 | 5.0 | 2030 | 30 | $1,492 | included in FOM | 0% | 0% | $31.65 | 35% | $63.57 |
| Wind | Offshore, Wind Class 12 | 0 | 200 | 2027 | 5.0 | 2032 | 30 | $8,341 | included in FOM | 0% | 0% | $69.26 | 35% | $169.16 |
| Wind | Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case | by location | 20 | 2025 | 3 | 2028 | 30 | $2,434 | included in FOM | 0% | 0% | $34.87 | 35% | $60.58 |
| Wind | Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case | by location | 200 | 2025 | 5 | 2030 | 30 | $1,354 | included in FOM | 0% | 0% | $28.45 | 35% | $60.58 |
| Wind | Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case | by location | 200 | 2025 | 5 | 2030 | 30 | $1,422 | included in FOM | 0% | 0% | $28.45 | 35% | $60.58 |
| Wind | Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case | 0 | 200 | 2027 | 5 | 2032 | 30 | $6,011 | included in FOM | 0% | 0% | $63.21 | 35% | $121.92 |

[1] Assumed co-located

[23] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users)

## Table 7.4 – 2025 Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

| | | Operating Characteristics | | | | Environmental Data | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource Description | Average Full Load Heat Rate (HHV Btu/KWh) | Efficiency | EFOR (%) | POR (%) | Water Consumed (Gal/MWh) | SO2 (lbs/MMBtu) | NOx (lbs/MMBtu) | Hg (lbs/TBTu) | CO2 (lbs/MMBtu) |
| Biofuel | Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank | 8,295 | 41.13% | 2.50% | 5.0% | 27.1 | 0.00152 | 0.02000 | 0.000 | 117 |
| Natural Gas | SCCT Aero, with SCR | 9,447 | 36.12% | 2.90% | 3.9% | 27.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | SCCT Aero x4, with SCR | 9,447 | 36.12% | 2.90% | 3.9% | 27.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | SCCT Frame "F" x1, with SCR | 9,717 | 35.12% | 2.70% | 3.9% | 28.4 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR | 6,040 | 56.49% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR | 6,122 | 55.74% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 | 6,743 | 53.17% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00563 | 0.000 | 6 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 | 6,843 | 52.46% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00563 | 0.000 | 6 |
| Natural Gas | Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction | 8,295 | 41.13% | 2.50% | 5.0% | 27.1 | 0.00152 | 0.02131 | 0.000 | 117 |
| Natural Gas | SCCT Aero, with SCR + Δ for CT Brownfield construction | 9,447 | 36.12% | 2.90% | 3.9% | 27.0 | 0.00150 | 0.00799 | 0.000 | 117 |
| Natural Gas | SCCT Aero x4, with SCR + Δ for CT Brownfield construction | 9,447 | 36.12% | 2.90% | 3.9% | 27.0 | 0.00150 | 0.00799 | 0.000 | 117 |
| Natural Gas | SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction | 9,717 | 35.12% | 2.70% | 3.9% | 28.4 | 0.00150 | 0.00799 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction | 6,040 | 56.49% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00799 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction | 6,122 | 55.74% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00799 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction | 6,743 | 53.17% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00599 | 0.000 | 6 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction | 6,843 | 52.46% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00599 | 0.000 | 6 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability | 9,717 | 35.12% | 2.70% | 3.90% | 28.4 | 0.00000 | 0.00750 | 0.000 | 0 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability | 6,040 | 56.49% | 2.50% | 3.80% | 210.0 | 0.00000 | 0.00750 | 0.000 | 0 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability | 6,122 | 55.74% | 2.50% | 3.80% | 210.0 | 0.00000 | 0.00750 | 0.000 | 0 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 9,717 | 35.12% | 2.75% | 3.90% | 28.4 | 0.00196 | 0.00946 | 0.002 | 0 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 6,040 | 56.49% | 2.55% | 3.80% | 210.0 | 0.00196 | 0.00946 | 0.002 | 0 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | 6,122 | 55.74% | 2.55% | 3.80% | 210.0 | 0.00196 | 0.00946 | 0.002 | 0 |
| Hydrogen | SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 9,717 | 35.12% | 2.75% | 3.90% | 28.4 | 0.00196 | 0.00946 | 0.002 | 0 |
| Hydrogen | CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 6,040 | 56.49% | 2.55% | 3.80% | 210.0 | 0.00196 | 0.00946 | 0.002 | 0 |
| Hydrogen | CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | 6,122 | 55.74% | 2.55% | 3.80% | 210.0 | 0.00196 | 0.00946 | 0.002 | 0 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 | 6,040 | 56.49% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 | 6,122 | 55.74% | 2.50% | 3.8% | 210.0 | 0.00150 | 0.00750 | 0.000 | 117 |
| Natural Gas | CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS | 6,743 | 53.17% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00563 | 0.000 | 6 |
| Natural Gas | CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS | 6,843 | 52.46% | 2.50% | 3.8% | 323.4 | 0.00150 | 0.00563 | 0.000 | 6 |
| Hydrogen | Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day | N/A | 79.13% | 1.50% | 1.5% | 45.7 | 0.00000 | 0.00000 | 0.000 | 0 |
| Coal | CCS Dave Johnston 4 (costs on post retrofit basis) | 14,795 | 23.06% | 7.50% | 7.50% | 186.0 | 10.00000 | 0.07100 | 0.304 | 10 |
| Coal | CCS Hunter 1-3 (costs on post retrofit basis) | 14,011 | 24.35% | 7.50% | 7.50% | 186.0 | 10.00000 | 0.07100 | 0.304 | 10 |
| Coal | CCS Huntington 1&2 (costs on post retrofit basis) | 13,662 | 24.98% | 7.50% | 7.50% | 186.0 | 10.00000 | 0.07100 | 0.304 | 10 |
| Coal | CCS Jim Bridger 3&4 (costs on post retrofit basis) | 14,483 | 23.56% | 7.50% | 7.50% | 186.0 | 10.00000 | 0.07100 | 0.304 | 10 |
| Coal | CCS Wyodak (costs on post retrofit basis) | 16,653 | 20.49% | 7.50% | 7.50% | 186.0 | 10.00000 | 0.07100 | 0.304 | 10 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Moderate Technology Case | 9,180 | 37% | 2% | 5% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Advanced Technology Case | 9,180 | 37% | 2% | 5% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage | 12,626 | 37.17% | 2.00% | 5.0% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Nuclear | Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage | 12,626 | 37.17% | 2.00% | 5.0% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Nuclear | Large Light Water Reactor, Moderate Technology Case | 10,497 | 33% | 2% | 5% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Nuclear | Large Light Water Reactor, Advanced Technology Case | 10,497 | 33% | 2% | 5% | 720.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Geothermal | Near Field Enhanhanced Geothermal System (NF-EGS) Binary | N/A | N/A | 10% | 10% | 510.0 | n/a | n/a | n/a | n/a |
| Geothermal | Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case | N/A | N/A | 10.00% | 10.00% | 510.0 | n/a | n/a | n/a | n/a |

## Table 7.5 – 2025 Non-Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

| | | Operating Characteristics | | | | Environmental Data | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource Description | Average Full Load Heat Rate (HHV Btu/KWh) | Efficiency | EFOR (%) | POR (%) | Water Consumed (Gal/MWh) | SO2 (lbs/MMBtu) | NOx (lbs/MMBtu) | Hg (lbs/TBTu) | CO2 (lbs/MMBtu) |
| Storage[1] | Li-Ion, 4-hour, 20 MW | n/a | 85% | 1.0% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage[1] | Li-Ion, 4-hour, 200 MW | n/a | 85% | 1% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage[1] | Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW | n/a | 85.00% | 1.00% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage[1] | Li-Ion, 4-hour, 1000 MW | n/a | 85% | 1.0% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Gravity Battery, 4-hour, 1000 MW | n/a | 83% | 1.0% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW | n/a | 83.00% | 1.00% | included in CF | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Adiabatic CAES, 500 MW, 4000 MWh | n/a | 63% | 1.1% | 1.1% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | 100-hour Iron Air | n/a | 43% | 1.0% | included in CF | 0.0 | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Hydro, Two New Reservoirs, 4-hour | n/a | 80% | 2.0% | 4.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Hydro, Two New Reservoirs, 10-hour | n/a | 80% | 2.0% | 4.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Hydro, One New Reservoir, 4-hour | n/a | 80% | 2.0% | 4.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Hydro, One New Reservoir, 10-hour | n/a | 80% | 2.0% | 4.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Thermal Energy Storage, 10-hour | n/a | 55% | 2.0% | 3.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Storage | Pumped Thermal Energy Storage, 24-hour | n/a | 55% | 2.0% | 3.0% | n/a | 0.00000 | 0.00000 | 0.000 | 0 |
| Solar | PV, 20 MW, Class 1-10 | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Solar | PV, 200 MW, Class 1-10 | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Solar | PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Solar | PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 1-10, 20 MW | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 1-6, 200 MW | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 7, 200 MW | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Offshore, Wind Class 12 | N/A | max CF: 47% | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case | N/A | by location | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |
| Wind | Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case | N/A | max CF: 47% | Included with CF | Included with CF | n/a | n/a | n/a | n/a | n/a |

[1] Assumed co-located

## Table 7.6 – 2025 IRP Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

| | Additional Attributes | | | | | | | Fixed O&M | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource Description | Modeled IRP | Elevation (AFSL) | Total Capital Cost | Demolition Cost | Payment Factor (real levelized) | Annual Payment ($/kW-Yr) | Capacity Factor | O&M ($/kW-Yr) | Capitalized Premium | O&M Capitalized ($/kW-Yr) | Gas Transport ($/kW-Yr) | Total Fixed O&M ($/kW-Yr) | Total Fixed Cost ($/kW-Yr) | Total Fixed Cost Converted ($/MWh) |
| Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank | Yes | 0 | $ 2,130.94 | $ 14.59 | 6.890% | $147.83 | 92.50% | $42.82 | 2.62% | $1.12 | $0.00 | $43.94 | $191.77 | $23.67 |
| SCCT Aero, with SCR | No | 0 | $ 2,612.80 | $ 32.46 | 6.101% | $161.39 | 33.00% | $12.42 | 2.62% | $0.32 | $0.00 | $12.74 | $174.13 | $60.24 |
| SCCT Aero x4, with SCR | No | 0 | $ 1,789.35 | $ 32.46 | 6.104% | $111.20 | 33.00% | $9.93 | 2.62% | $0.26 | $0.00 | $10.19 | $121.40 | $41.99 |
| SCCT Frame "F" x1, with SCR | Yes | 0 | $ 1,386.92 | $ 12.13 | 6.100% | $85.34 | 33.00% | $27.92 | 2.62% | $0.73 | $0.00 | $28.65 | $114.00 | $39.43 |
| Goshen | Yes | 2,814 | $ 1,400.79 | $ 12.13 | 6.100% | $86.19 | 33.00% | $27.92 | 2.62% | $0.73 | $96.20 | $124.85 | $211.04 | $73.00 |
| Wasatch Front | Yes | 4,225 | $ 1,373.05 | $ 12.13 | 6.100% | $84.50 | 33.00% | $27.92 | 2.62% | $0.73 | $14.72 | $43.38 | $127.87 | $44.23 |
| Wyoming East | Yes | 6,130 | $ 1,373.05 | $ 12.13 | 6.100% | $84.50 | 33.00% | $27.92 | 2.62% | $0.73 | $25.80 | $54.45 | $138.95 | $48.07 |
| CCCT Dry "H", 1X1, DF, with SCR | Yes | 0 | $ 1,839.00 | $ 12.08 | 6.233% | $115.38 | 78.00% | $42.44 | 2.62% | $1.11 | $0.00 | $43.55 | $158.93 | $23.26 |
| Goshen | Yes | 2,814 | $ 1,857.39 | $ 12.08 | 6.233% | $116.52 | 78.00% | $42.44 | 2.62% | $1.11 | $60.34 | $103.89 | $220.41 | $32.26 |
| Wasatch Front | Yes | 4,225 | $ 1,820.61 | $ 12.08 | 6.233% | $114.23 | 78.00% | $42.44 | 2.62% | $1.11 | $9.25 | $52.81 | $167.04 | $24.45 |
| Wyoming East | Yes | 6,130 | $ 1,820.61 | $ 12.08 | 6.233% | $114.23 | 78.00% | $42.44 | 2.62% | $1.11 | $16.33 | $59.88 | $174.11 | $25.48 |
| CCCT Dry "H", 2X1, DF, with SCR | Yes | 0 | $ 1,553.26 | $ 11.89 | 6.234% | $97.57 | 78.00% | $35.18 | 2.62% | $0.92 | $0.00 | $36.10 | $133.67 | $19.56 |
| Goshen | Yes | 2,814 | $ 1,568.79 | $ 11.89 | 6.234% | $98.54 | 78.00% | $35.18 | 2.62% | $0.92 | $61.16 | $97.26 | $195.80 | $28.66 |
| Wasatch Front | Yes | 4,225 | $ 1,537.73 | $ 11.89 | 6.234% | $96.60 | 78.00% | $35.18 | 2.62% | $0.92 | $9.38 | $45.48 | $142.08 | $20.79 |
| Wyoming East | Yes | 6,130 | $ 1,537.73 | $ 11.89 | 6.234% | $96.60 | 78.00% | $35.18 | 2.62% | $0.92 | $16.55 | $52.65 | $149.26 | $21.84 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 | No | 0 | $ 3,429.38 | $ 65.28 | 6.239% | $218.03 | 78.00% | $77.07 | 5.54% | $4.27 | $0.00 | $81.34 | $299.37 | $43.81 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 | No | 0 | $ 2,846.02 | $ 65.08 | 6.241% | $181.68 | 78.00% | $62.99 | 5.54% | $3.49 | $0.00 | $66.48 | $248.16 | $36.32 |
| Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction | No | 0 | $ 1,917.85 | $ 14.59 | 6.891% | $133.16 | 33.00% | $42.82 | 2.62% | $1.12 | $0.00 | $43.94 | $177.10 | $61.26 |
| SCCT Aero, with SCR + Δ for CT Brownfield construction | No | 0 | $ 2,351.52 | $ 32.46 | 6.102% | $145.47 | 33.00% | $12.42 | 2.62% | $0.32 | $0.00 | $12.74 | $158.21 | $54.73 |
| SCCT Aero x4, with SCR + Δ for CT Brownfield construction | No | 0 | $ 1,610.42 | $ 32.46 | 6.105% | $100.30 | 33.00% | $9.93 | 2.62% | $0.26 | $0.00 | $10.19 | $110.49 | $38.22 |
| SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction | Yes | 0 | $ 1,248.23 | $ 12.13 | 6.100% | $76.88 | 33.00% | $27.92 | 2.62% | $0.73 | $0.00 | $28.65 | $105.53 | $36.51 |
| Goshen-Brownfield | No | 2,814 | $ 1,260.71 | $ 12.13 | 6.100% | $77.64 | 33.00% | $27.92 | 2.62% | $0.73 | $96.20 | $124.85 | $202.50 | $70.05 |
| Wasatch Front-Brownfield | Yes | 4,225 | $ 1,235.75 | $ 12.13 | 6.100% | $76.12 | 33.00% | $27.92 | 2.62% | $0.73 | $14.72 | $43.38 | $119.50 | $41.34 |
| Wyoming East-Brownfield | Yes | 6,130 | $ 1,235.75 | $ 12.13 | 6.100% | $76.12 | 33.00% | $27.92 | 2.62% | $0.73 | $25.80 | $54.45 | $130.57 | $45.17 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction | Yes | 0 | $ 1,655.10 | $ 12.08 | 6.234% | $103.93 | 78.00% | $42.44 | 2.62% | $1.11 | $0.00 | $43.55 | $147.48 | $21.58 |
| Goshen-Brownfield | No | 2,814 | $ 1,671.65 | $ 12.08 | 6.234% | $104.96 | 78.00% | $42.44 | 2.62% | $1.11 | $60.34 | $103.89 | $208.85 | $30.57 |
| Wasatch Front-Brownfield | Yes | 4,225 | $ 1,638.55 | $ 12.08 | 6.234% | $102.90 | 78.00% | $42.44 | 2.62% | $1.11 | $9.25 | $52.81 | $155.71 | $22.79 |
| Wyoming East-Brownfield | Yes | 6,130 | $ 1,638.55 | $ 12.08 | 6.234% | $102.90 | 78.00% | $42.44 | 2.62% | $1.11 | $16.33 | $59.88 | $162.78 | $23.82 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction | Yes | 0 | $ 1,397.93 | $ 11.89 | 6.234% | $87.89 | 78.00% | $35.18 | 2.62% | $0.92 | $0.00 | $36.10 | $123.99 | $18.15 |
| Goshen-Brownfield | No | 2,814 | $ 1,411.91 | $ 11.89 | 6.234% | $88.76 | 78.00% | $35.18 | 2.62% | $0.92 | $61.16 | $97.26 | $186.02 | $27.22 |
| Wasatch Front-Brownfield | Yes | 4,225 | $ 1,383.95 | $ 11.89 | 6.234% | $87.02 | 78.00% | $35.18 | 2.62% | $0.92 | $9.38 | $45.48 | $132.50 | $19.39 |
| Wyoming East-Brownfield | Yes | 6,130 | $ 1,383.95 | $ 11.89 | 6.234% | $87.02 | 78.00% | $35.18 | 2.62% | $0.92 | $16.55 | $52.65 | $139.67 | $20.44 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction | No | 0 | $ 3,086.44 | $ 65.28 | 6.240% | $196.67 | 78.00% | $77.07 | 5.54% | $4.27 | $0.00 | $81.34 | $278.00 | $40.69 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction | No | 0 | $ 2,561.42 | $ 65.08 | 6.242% | $163.95 | 78.00% | $62.99 | 5.54% | $3.49 | $0.00 | $66.48 | $230.43 | $33.72 |
| SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability | No | 0 | $ 1,594.96 | $ 13.95 | 5.605% | $90.18 | 33.00% | $27.92 | 2.62% | $0.73 | $0.00 | $28.65 | $118.83 | $41.11 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability | No | 0 | $ 2,114.85 | $ 13.89 | 5.604% | $119.29 | 78.00% | $42.44 | 2.62% | $1.11 | $0.00 | $43.55 | $162.85 | $23.83 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability | No | 0 | $ 1,786.25 | $ 13.67 | 5.604% | $100.87 | 78.00% | $35.18 | 2.62% | $0.92 | $0.00 | $36.10 | $136.97 | $20.05 |
| SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | No | 0 | $ 2,585.93 | $ 27.13 | 9.271% | $242.26 | 33.00% | $35.12 | 2.62% | $0.92 | $0.00 | $36.04 | $278.30 | $96.27 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | No | 0 | $ 3,038.01 | $ 27.08 | 9.254% | $283.64 | 78.00% | $49.64 | 2.62% | $1.30 | $0.00 | $50.94 | $334.59 | $48.97 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | No | 0 | $ 2,752.27 | $ 26.89 | 9.263% | $257.43 | 78.00% | $42.38 | 2.62% | $1.11 | $0.00 | $43.49 | $300.93 | $44.04 |
| SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | No | 0 | $ 2,097.84 | $ 27.13 | 9.255% | $196.67 | 33.00% | $40.78 | 2.62% | $1.07 | $0.00 | $41.85 | $238.51 | $82.51 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | No | 0 | $ 2,549.91 | $ 27.08 | 9.245% | $238.24 | 78.00% | $55.30 | 2.62% | $1.45 | $0.00 | $56.75 | $294.99 | $43.17 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | No | 0 | $ 2,264.18 | $ 26.89 | 9.250% | $211.92 | 78.00% | $48.04 | 2.62% | $1.26 | $0.00 | $49.30 | $261.22 | $38.23 |
| CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 | No | 0 | $ 1,831.63 | $ 12.08 | 6.233% | $114.92 | 78.00% | $41.33 | 2.62% | $1.08 | $0.00 | $42.41 | $157.33 | $23.02 |
| CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 | No | 0 | $ 1,517.84 | $ 11.89 | 6.234% | $95.36 | 78.00% | $34.07 | 2.62% | $0.89 | $0.00 | $34.96 | $130.32 | $19.07 |
| CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS | No | 0 | $ 3,260.88 | $ 65.28 | 6.233% | $207.32 | 78.00% | $72.60 | 5.54% | $4.02 | $0.00 | $76.62 | $283.94 | $41.56 |
| CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS | No | 0 | $ 2,637.12 | $ 65.08 | 6.234% | $168.46 | 78.00% | $57.74 | 5.54% | $3.20 | $0.00 | $60.94 | $229.40 | $33.57 |
| Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer | Yes | 0 | $ 2,858.50 | $ 44.94 | 4.170% | $121.07 | 98.00% | $60.95 | 0.00% | $0.00 | $0.00 | $60.95 | $182.03 | $21.20 |
| Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day | No | 0 | $ 560.99 | $ 32.46 | 4.170% | $24.75 | 97.00% | $10.28 | 0.00% | $0.00 | $0.00 | $10.28 | $35.03 | $4.12 |
| Δ CCS Dave Johnston 4 (costs on post retrofit basis) | No | 5,541 | $ 3,500.78 | $ 53.20 | 6.447% | $229.12 | 85.00% | $277.68 | 5.54% | $15.38 | $0.00 | $293.06 | $522.19 | $70.13 |
| Δ CCS Hunter 1-3 (costs on post retrofit basis) | No | 6,429 | $ 2,951.20 | $ 53.20 | 6.451% | $193.81 | 85.00% | $235.36 | 5.54% | $13.04 | $0.00 | $248.39 | $442.21 | $59.39 |
| Δ CCS Huntington 1&2 (costs on post retrofit basis) | No | 6,933 | $ 2,951.40 | $ 53.20 | 6.451% | $193.83 | 85.00% | $242.12 | 5.54% | $13.41 | $0.00 | $255.53 | $449.36 | $60.35 |
| Δ CCS Jim Bridger 3&4 (costs on post retrofit basis) | Yes | 7,513 | $ 2,598.38 | $ 53.20 | 6.454% | $171.13 | 85.00% | $254.91 | 5.54% | $14.12 | $0.00 | $269.03 | $440.16 | $59.11 |
| Δ CCS Wyodak (costs on post retrofit basis) | No | 4,448 | $ 3,504.25 | $ 53.20 | 6.447% | $229.35 | 85.00% | $309.51 | 5.54% | $17.15 | $0.00 | $326.65 | $556.00 | $74.67 |
| Small Modular Reactor or Advanced Reactor, Moderate Technology Case | Yes | N/A | $ 9,662.09 | $ 17.00 | 5.042% | $488.02 | 93.00% | $97.42 | 9.42% | $9.18 | $0.00 | $106.60 | $594.62 | $72.99 |
| Goshen | Yes | 2,814 | $ 9,855.33 | $ 17.00 | 5.042% | $497.76 | 93.00% | $97.42 | 9.42% | $9.18 | $0.00 | $106.60 | $604.36 | $74.18 |
| Wasatch Front | Yes | 4,225 | $ 9,855.33 | $ 17.00 | 5.042% | $497.76 | 93.00% | $97.42 | 9.42% | $9.18 | $0.00 | $106.60 | $604.36 | $74.18 |
| Wyoming East | Yes | 6,130 | $ 9,565.47 | $ 17.00 | 5.042% | $483.15 | 93.00% | $97.42 | 9.42% | $9.18 | $0.00 | $106.60 | $589.75 | $72.39 |
| Small Modular Reactor or Advanced Reactor, Advanced Technology Case | No | N/A | $ 6,368.23 | $ 12.00 | 5.042% | $321.69 | 93.00% | $84.53 | 9.42% | $7.97 | $0.00 | $92.49 | $414.18 | $50.84 |
| Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage | No | N/A | $ 10,628.30 | $ 17.00 | 5.042% | $536.74 | 93.00% | $107.16 | 9.42% | $10.10 | $0.00 | $117.26 | $654.00 | $80.28 |
| Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage | No | N/A | $ 7,005.05 | $ 12.00 | 5.042% | $353.80 | 93.00% | $92.98 | 9.42% | $8.76 | $0.00 | $101.74 | $455.54 | $55.92 |
| Large Light Water Reactor, Moderate Technology Case | No | N/A | $ 7,562.87 | $ 10.00 | 5.042% | $381.82 | 93.00% | $125.36 | 9.42% | $11.81 | $0.00 | $137.17 | $518.99 | $63.71 |
| Large Light Water Reactor, Advanced Technology Case | No | N/A | $ 6,265.25 | $ 9.00 | 5.042% | $316.35 | 93.00% | $90.26 | 9.42% | $8.51 | $0.00 | $98.76 | $415.11 | $50.95 |
| Near Field Enhanhanced Geothermal System (NF-EGS) Binary | Yes | N/A | $ 7,593.06 | $ 125.09 | 6.262% | $483.31 | 80.00% | $194.00 | 0.87% | $1.69 | $0.00 | $195.69 | $679.00 | $96.89 |
| Southern OR | Yes | 497 | $ 8,883.88 | $ 125.09 | 6.262% | $564.14 | 80.00% | $194.00 | 0.87% | $1.69 | $0.00 | $195.69 | $759.83 | $108.42 |
| Wasatch Front | Yes | 4,225 | $ 7,593.06 | $ 125.09 | 6.262% | $483.31 | 80.00% | $194.00 | 0.87% | $1.69 | $0.00 | $195.69 | $679.00 | $96.89 |

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

## Table 7.7 – 2025 IRP Non-Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

| | Additional Attributes | | | | | | | Fixed O&M | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource Description | Modeled IRP | Elevation (AFSL) | Total Capital Cost | Demolition Cost | Payment Factor (real levelized) | Annual Payment ($/kW-Yr) | Capacity Factor | O&M ($/kW-Yr) | Capitalized Premium | O&M Capitalized ($/kW-Yr) | Total Fixed O&M ($/kW-Yr) | Total Fixed Cost ($/kW-Yr) | Total Fixed Cost Converted ($/MWh) |
| PV, 20 MW, Class 1-10 | Yes | by location | $ 1,964.64 | $ 39.29 | 6.861% | $137.49 | 27.33% | $18.16 | 1.37% | $0.25 | $18.41 | $155.90 | $65.11 |
| Portland North Coast | Yes | 19 | $ 2,082.51 | $ 39.29 | 6.861% | $145.58 | 24.49% | $18.16 | 1.37% | $0.25 | $18.41 | $163.99 | $76.45 |
| Southern OR | Yes | 497 | $ 2,180.75 | $ 39.29 | 6.861% | $152.32 | 29.29% | $18.16 | 1.37% | $0.25 | $18.41 | $170.73 | $66.54 |
| Walla Walla | Yes | 2,353 | $ 2,003.93 | $ 39.29 | 6.861% | $140.19 | 25.96% | $18.16 | 1.37% | $0.25 | $18.41 | $158.60 | $69.74 |
| Goshen | Yes | 2,814 | $ 1,984.28 | $ 39.29 | 6.861% | $138.84 | 27.79% | $18.16 | 1.37% | $0.25 | $18.41 | $157.25 | $64.59 |
| Wasatch Front | Yes | 4,225 | $ 1,964.64 | $ 39.29 | 6.861% | $137.49 | 29.00% | $18.16 | 1.37% | $0.25 | $18.41 | $155.90 | $61.38 |
| Wyoming East | Yes | 6,130 | $ 1,964.64 | $ 39.29 | 6.861% | $137.49 | 27.47% | $18.16 | 1.37% | $0.25 | $18.41 | $155.90 | $64.79 |
| PV, 200 MW, Class 1-10 | Yes | by location | $ 1,216.55 | $ 24.33 | 6.861% | $85.14 | 27.33% | $20.52 | 1.37% | $0.28 | $20.80 | $105.93 | $44.24 |
| Portland North Coast | Yes | 19 | $ 1,289.55 | $ 24.33 | 6.861% | $90.15 | 24.49% | $20.52 | 1.37% | $0.28 | $20.80 | $110.94 | $51.72 |
| Southern OR | Yes | 497 | $ 1,350.37 | $ 24.33 | 6.861% | $94.32 | 29.29% | $20.52 | 1.37% | $0.28 | $20.80 | $115.12 | $44.87 |
| Walla Walla | Yes | 2,353 | $ 1,240.88 | $ 24.33 | 6.861% | $86.81 | 25.96% | $20.52 | 1.37% | $0.28 | $20.80 | $107.60 | $47.32 |
| Goshen | Yes | 2,814 | $ 1,228.72 | $ 24.33 | 6.861% | $85.97 | 27.79% | $20.52 | 1.37% | $0.28 | $20.80 | $106.77 | $43.86 |
| Wasatch Front | Yes | 4,225 | $ 1,216.55 | $ 24.33 | 6.861% | $85.14 | 29.00% | $20.52 | 1.37% | $0.28 | $20.80 | $105.93 | $41.71 |
| Wyoming East | Yes | 6,130 | $ 1,216.55 | $ 24.33 | 6.861% | $85.14 | 27.47% | $20.52 | 1.37% | $0.28 | $20.80 | $105.93 | $44.02 |
| PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case | No | by location | $ 1,832.22 | $ 37.33 | 6.862% | $128.29 | 27.33% | $17.24 | 1.37% | $0.24 | $17.48 | $145.76 | $60.88 |
| PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case | No | by location | $ 1,134.56 | $ 23.11 | 6.862% | $79.44 | 27.33% | $19.47 | 1.37% | $0.27 | $19.74 | $99.18 | $41.42 |
| Wind Class 1-10, 20 MW | Yes | by location | $ 2,554.58 | $ 63.57 | 6.292% | $164.73 | 29.07% | $38.79 | 4.39% | $1.70 | $40.49 | $205.22 | $80.60 |
| Portland North Coast | Yes | 19 | $ 2,835.59 | $ 63.57 | 6.292% | $182.42 | 24.91% | $38.79 | 4.39% | $1.70 | $40.49 | $222.90 | $102.14 |
| Southern OR | Yes | 497 | $ 3,014.41 | $ 63.57 | 6.292% | $193.67 | 25.18% | $38.79 | 4.39% | $1.70 | $40.49 | $234.15 | $106.14 |
| Walla Walla | Yes | 2,353 | $ 2,656.77 | $ 63.57 | 6.292% | $171.16 | 23.13% | $38.79 | 4.39% | $1.70 | $40.49 | $211.65 | $104.46 |
| Goshen | Yes | 2,814 | $ 2,605.68 | $ 63.57 | 6.292% | $167.95 | 34.26% | $38.79 | 4.39% | $1.70 | $40.49 | $208.44 | $69.45 |
| Wasatch Front | Yes | 4,225 | $ 2,580.13 | $ 63.57 | 6.292% | $166.34 | 33.69% | $38.79 | 4.39% | $1.70 | $40.49 | $206.83 | $70.08 |
| Wyoming East | Yes | 6,130 | $ 2,503.49 | $ 63.57 | 6.292% | $161.52 | 33.22% | $38.79 | 4.39% | $1.70 | $40.49 | $202.01 | $69.41 |
| Wind Class 1-6, 200 MW | Yes | by location | $ 1,421.10 | $ 63.57 | 6.316% | $93.77 | 34.37% | $31.65 | 4.39% | $1.39 | $33.04 | $126.81 | $42.12 |
| Portland North Coast | Yes | 19 | $ 1,577.43 | $ 63.57 | 6.316% | $103.65 | 37.62% | $31.65 | 4.39% | $1.39 | $33.04 | $136.68 | $41.47 |
| Southern OR | Yes | 497 | $ 1,676.90 | $ 63.57 | 6.316% | $109.93 | 34.06% | $31.65 | 4.39% | $1.39 | $33.04 | $142.97 | $47.92 |
| Walla Walla | Yes | 2,353 | $ 1,477.95 | $ 63.57 | 6.316% | $97.36 | 32.59% | $31.65 | 4.39% | $1.39 | $33.04 | $130.40 | $45.68 |
| Goshen | Yes | 2,814 | $ 1,449.53 | $ 63.57 | 6.316% | $95.57 | 30.28% | $31.65 | 4.39% | $1.39 | $33.04 | $128.61 | $48.49 |
| Wasatch Front | Yes | 4,225 | $ 1,435.32 | $ 63.57 | 6.316% | $94.67 | 30.42% | $31.65 | 4.39% | $1.39 | $33.04 | $127.71 | $47.93 |
| Wyoming East | Yes | 6,130 | $ 1,392.68 | $ 63.57 | 6.316% | $91.98 | 41.25% | $31.65 | 4.39% | $1.39 | $33.04 | $125.02 | $34.60 |
| Wind Class 7, 200 MW | No | by location | $ 1,491.78 | $ 63.57 | 6.313% | $98.19 | 34.37% | $31.65 | 4.39% | $1.39 | $33.04 | $131.23 | $43.59 |
| Offshore, Wind Class 12 | Yes | 0 | $ 8,340.57 | $ 169.16 | 5.202% | $442.68 | 31.54% | $69.26 | 4.39% | $3.04 | $72.30 | $514.98 | $186.38 |
| Southern OR | Yes | 497 | $ 9,841.87 | $ 169.16 | 5.202% | $520.77 | 48.94% | $69.26 | 4.39% | $3.04 | $72.30 | $593.07 | $138.33 |
| Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case | No | by location | $ 2,434.26 | $ 60.58 | 6.292% | $156.98 | 29.07% | $34.87 | 4.39% | $1.53 | $36.40 | $193.37 | $75.95 |
| Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case | No | by location | $ 1,354.17 | $ 60.58 | 6.316% | $89.36 | 34.37% | $28.45 | 4.39% | $1.25 | $29.70 | $119.06 | $39.54 |
| Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case | No | by location | $ 1,421.51 | $ 60.58 | 6.313% | $93.56 | 34.37% | $28.45 | 4.39% | $1.25 | $29.70 | $123.27 | $40.94 |
| Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case | No | 0 | $ 6,011.05 | $ 121.92 | 4.841% | $296.90 | 84.43% | $63.21 | 4.39% | $2.78 | $65.99 | $362.89 | $49.06 |

## Table 7.8 – 2025 IRP Storage Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

| | Additional Attributes | | | | | | | | Fixed O&M | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource Description | Modeled IRP | Elevation (AFSL) | Total Capital Cost | Demolition Cost | Payment Factor (real levelized) | Annual Payment ($/kW-Yr) | Capacity Factor | Storage Efficiency | O&M ($/kW-Yr) | Capitalized Premium | O&M Capitalized ($/kW-Yr) | Total Fixed O&M ($/kW-Yr) | Total Fixed Cost ($/kW-Yr) | Total Fixed Cost Converted ($/MWh) |
| Li-Ion, 4-hour, 20 MW[1] | No | N/A | $ 1,747.61 | $ 29.94 | 5.354% | $95.17 | 16.67% | 85% | $45.05 | 0.00% | $ - | $45.05 | $140.22 | $96.04 |
| Li-Ion, 4-hour, 200 MW[1] | Yes | N/A | $ 1,497.89 | $ 25.66 | 5.354% | $81.57 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $120.34 | $82.42 |
| Portland North Coast | Yes | 19 | $ 1,587.77 | $ 25.66 | 5.354% | $86.38 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $125.15 | $85.72 |
| Southern OR | Yes | 497 | $ 1,617.73 | $ 25.66 | 5.354% | $87.99 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $126.75 | $86.82 |
| Walla Walla | Yes | 2,353 | $ 1,542.83 | $ 25.66 | 5.354% | $83.98 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $122.74 | $84.07 |
| Goshen | Yes | 2,814 | $ 1,527.85 | $ 25.66 | 5.354% | $83.18 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $121.94 | $83.52 |
| Wasatch Front | Yes | 4,225 | $ 1,542.83 | $ 25.66 | 4.452% | $69.83 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $108.60 | $74.38 |
| Wyoming East | Yes | 6,130 | $ 1,482.92 | $ 25.66 | 4.452% | $67.16 | 16.67% | 85% | $38.77 | 0.00% | $0.00 | $38.77 | $105.93 | $72.55 |
| Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1] | Yes | N/A | $ 2,556.57 | $ 46.19 | 5.355% | $139.38 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $209.16 | $71.63 |
| Portland North Coast | Yes | 19 | $ 2,709.97 | $ 46.19 | 5.355% | $147.59 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $217.37 | $74.44 |
| Southern OR | Yes | 497 | $ 2,761.10 | $ 46.19 | 5.355% | $150.33 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $220.11 | $75.38 |
| Walla Walla | Yes | 2,353 | $ 2,633.27 | $ 46.19 | 5.355% | $143.48 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $213.27 | $73.04 |
| Goshen | Yes | 2,814 | $ 2,607.71 | $ 46.19 | 5.355% | $142.12 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $211.90 | $72.57 |
| Wasatch Front | Yes | 4,225 | $ 2,633.27 | $ 46.19 | 4.453% | $119.32 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $189.10 | $64.76 |
| Wyoming East | Yes | 6,130 | $ 2,531.01 | $ 46.19 | 4.453% | $114.76 | 33.33% | 85% | $69.78 | 0.00% | $0.00 | $69.78 | $184.54 | $63.20 |
| Li-Ion, 4-hour, 1000 MW[1] | No | N/A | $ 1,459.50 | $ 25.66 | 5.356% | $79.55 | 16.67% | 85% | $36.92 | 0.00% | $0.00 | $36.92 | $116.47 | $79.77 |
| Gravity Battery, 4-hour, 1000 MW | Yes | N/A | $ 2,020.99 | $ 0.19 | 2.916% | $58.94 | 16.67% | 83% | $50.51 | 0.00% | $0.00 | $50.51 | $109.45 | $74.97 |
| Wasatch Front | Yes | 4,225 | $ 2,081.62 | $ 0.19 | 2.916% | $60.71 | 16.67% | 83% | $50.51 | 0.00% | $0.00 | $50.51 | $111.22 | $76.18 |
| Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW | No | N/A | $ 3,006.34 | $ 0.35 | 2.916% | $87.68 | 33.33% | 83% | $90.92 | 5.48% | $4.98 | $95.90 | $183.58 | $62.87 |
| Adiabatic CAES, 500 MW, 4000 MWh | No | N/A | $ 3,754.00 | $ 49.31 | 4.288% | $163.09 | 33.33% | 63% | $19.20 | 0.00% | $0.00 | $19.20 | $182.29 | $62.43 |
| 100-hour Iron Air | Yes | N/A | $ 2,729.67 | $ 171.06 | 4.581% | $132.88 | 30.07% | 43% | $21.04 | 2.62% | $0.55 | $21.59 | $154.47 | $58.64 |
| Portland North Coast | Yes | 19 | $ 2,893.45 | $ 171.06 | 5.484% | $168.06 | 30.07% | 43% | $21.04 | 2.62% | $0.55 | $21.59 | $189.65 | $72.00 |
| Wasatch Front | Yes | 4,225 | $ 2,811.56 | $ 171.06 | 4.581% | $136.63 | 30.07% | 43% | $21.04 | 2.62% | $0.55 | $21.59 | $158.22 | $60.07 |
| Pumped Hydro, Two New Reservoirs, 4-hour | No | N/A | $ 2,984.23 | $ 149.21 | 3.121% | $97.79 | 16.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $118.52 | $81.18 |
| Pumped Hydro, Two New Reservoirs, 10-hour | Yes | N/A | $ 4,158.90 | $ 207.95 | 3.121% | $136.29 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $157.02 | $43.02 |
| Portland North Coast | Yes | 19 | $ 4,408.44 | $ 207.95 | 3.121% | $144.08 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $164.81 | $45.15 |
| Southern OR | Yes | 497 | $ 4,491.61 | $ 207.95 | 3.121% | $146.67 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $167.40 | $45.86 |
| Goshen | Yes | 2,814 | $ 4,242.08 | $ 207.95 | 3.121% | $138.89 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $159.61 | $43.73 |
| Wasatch Front | Yes | 4,225 | $ 4,283.67 | $ 207.95 | 2.582% | $115.97 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $136.70 | $37.45 |
| Wyoming East | Yes | 6,130 | $ 4,117.31 | $ 207.95 | 2.582% | $111.68 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $132.41 | $36.28 |
| Pumped Hydro, One New Reservoir, 4-hour | No | N/A | $ 2,883.24 | $ 144.16 | 3.121% | $94.49 | 16.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $115.21 | $78.91 |
| Pumped Hydro, One New Reservoir, 10-hour | No | N/A | $ 3,537.41 | $ 176.87 | 3.121% | $115.92 | 41.67% | 80% | $20.20 | 2.62% | $0.53 | $20.73 | $136.65 | $37.44 |
| Pumped Thermal Energy Storage, 10-hour | No | N/A | $ 6,173.76 | $ 60.00 | 3.361% | $209.52 | 35.48% | 55% | $2.00 | 2.62% | $0.05 | $2.05 | $211.57 | $68.06 |
| Pumped Thermal Energy Storage, 24-hour | No | N/A | $ 11,525.17 | $ 60.00 | 3.362% | $389.49 | 35.48% | 55% | $1.00 | 1.37% | $0.01 | $1.01 | $390.51 | $125.63 |

[1]Assumed co-located

## Table 7.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

| | Variable O&M | | | | | Credits | | |
|---|---|---|---|---|---|---|---|---|
| Resource Description | Levelized Fuel ($/MWh) | O&M ($/MWh) | Capitalized Premium | O&M Capitalized ($/MWh) | Total Resource Cost ($/MWh) | Tax Credits ($/MWh) (ITC already applied) | Total Resource Cost with PTC / ITC Credits ($/MWh) | Total Fixed Cost with Tax Credit ($/kW-yr) |
| Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank | $ 357.85 | $6.93 | 14.39% | $1.00 | $389.44 | - | $389.44 | $191.77 |
| SCCT Aero, with SCR | $ 53.04 | $7.40 | 14.39% | $1.07 | $121.75 | - | $121.75 | $174.13 |
| SCCT Aero x4, with SCR | $ 53.04 | $5.92 | 14.39% | $0.85 | $101.81 | - | $101.81 | $121.40 |
| SCCT Frame "F" x1, with SCR | $ 54.56 | $7.75 | 14.39% | $1.12 | $102.86 | - | $102.86 | $114.00 |
| Goshen | $ 55.25 | $7.75 | 14.39% | $1.12 | $137.12 | - | $137.12 | $211.04 |
| Wasatch Front | $ 55.27 | $7.75 | 14.39% | $1.12 | $108.37 | - | $108.37 | $127.87 |
| Wyoming East | $ 47.47 | $7.75 | 14.39% | $1.12 | $104.40 | - | $104.40 | $138.95 |
| CCCT Dry "H", 1X1, DF, with SCR | $ 33.91 | $2.70 | 14.39% | $0.39 | $60.26 | - | $60.26 | $158.93 |
| Goshen | $ 34.65 | $2.70 | 14.39% | $0.39 | $70.00 | - | $70.00 | $220.41 |
| Wasatch Front | $ 34.74 | $2.70 | 14.39% | $0.39 | $62.27 | - | $62.27 | $167.04 |
| Wyoming East | $ 30.05 | $2.70 | 14.39% | $0.39 | $58.62 | - | $58.62 | $174.11 |
| CCCT Dry "H", 2X1, DF, with SCR | $ 34.37 | $2.28 | 14.39% | $0.33 | $56.54 | - | $56.54 | $133.67 |
| Goshen | $ 35.12 | $2.28 | 14.39% | $0.33 | $66.39 | - | $66.39 | $195.80 |
| Wasatch Front | $ 35.21 | $2.28 | 14.39% | $0.33 | $58.61 | - | $58.61 | $142.08 |
| Wyoming East | $ 30.45 | $2.28 | 14.39% | $0.33 | $54.90 | - | $54.90 | $149.26 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 | $ 37.86 | $5.32 | 11.52% | $0.61 | $87.60 | - | $87.60 | $299.37 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 | $ 38.42 | $4.83 | 11.52% | $0.56 | $80.12 | - | $80.12 | $248.16 |
| Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction | $ 46.57 | $6.24 | 14.39% | $0.90 | $114.97 | - | $114.97 | $177.10 |
| SCCT Aero, with SCR + Δ for CT Brownfield construction | $ 53.04 | $6.66 | 14.39% | $0.96 | $115.39 | - | $115.39 | $158.21 |
| SCCT Aero x4, with SCR + Δ for CT Brownfield construction | $ 53.04 | $5.33 | 14.39% | $0.77 | $97.36 | - | $97.36 | $110.49 |
| SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction | $ 54.56 | $6.98 | 14.39% | $1.00 | $99.05 | - | $99.05 | $105.53 |
| Goshen-Brownfield | $ 54.23 | $6.98 | 14.39% | $1.00 | $132.26 | - | $132.26 | $202.50 |
| Wasatch Front-Brownfield | $ 54.29 | $6.98 | 14.39% | $1.00 | $103.60 | - | $103.60 | $119.50 |
| Wyoming East-Brownfield | $ 53.90 | $6.98 | 14.39% | $1.00 | $107.05 | - | $107.05 | $130.57 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction | $ 33.91 | $2.43 | 14.39% | $0.35 | $58.28 | - | $58.28 | $147.48 |
| Goshen-Brownfield | $ 34.01 | $2.43 | 14.39% | $0.35 | $67.36 | - | $67.36 | $208.85 |
| Wasatch Front-Brownfield | $ 34.12 | $2.43 | 14.39% | $0.35 | $59.69 | - | $59.69 | $155.71 |
| Wyoming East-Brownfield | $ 34.12 | $2.43 | 14.39% | $0.35 | $60.72 | - | $60.72 | $162.78 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction | $ 34.37 | $2.05 | 14.39% | $0.30 | $54.87 | - | $54.87 | $123.99 |
| Goshen-Brownfield | $ 34.48 | $2.05 | 14.39% | $0.30 | $64.05 | - | $64.05 | $186.02 |
| Wasatch Front-Brownfield | $ 34.58 | $2.05 | 14.39% | $0.30 | $56.32 | - | $56.32 | $132.50 |
| Wyoming East-Brownfield | $ 34.58 | $2.05 | 14.39% | $0.30 | $57.37 | - | $57.37 | $139.67 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction | $ 37.86 | $4.78 | 11.52% | $0.55 | $83.88 | - | $83.88 | $278.00 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction | $ 38.42 | $4.34 | 11.52% | $0.50 | $76.99 | - | $76.99 | $230.43 |
| SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability | $ 54.56 | $8.91 | 14.39% | $1.28 | $105.86 | - | $105.86 | $118.83 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability | $ 33.91 | $3.11 | 14.39% | $0.45 | $61.30 | - | $61.30 | $162.85 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability | $ 34.37 | $2.62 | 14.39% | $0.38 | $57.42 | - | $57.42 | $136.97 |
| SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | $ 54.56 | $8.18 | 14.39% | $1.18 | $160.18 | - | $160.18 | $278.30 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | $ 33.91 | $3.13 | 14.39% | $0.45 | $86.46 | - | $86.46 | $334.59 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour | $ 34.37 | $2.70 | 14.39% | $0.39 | $81.51 | - | $81.51 | $300.93 |
| SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | $ 54.56 | $8.32 | 14.39% | $1.20 | $146.59 | - | $146.59 | $238.51 |
| CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | $ 33.91 | $3.27 | 14.39% | $0.47 | $80.83 | - | $80.83 | $294.99 |
| CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour | $ 34.37 | $2.85 | 14.39% | $0.41 | $75.86 | - | $75.86 | $261.22 |
| CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 | $ 33.91 | $2.68 | 14.39% | $0.39 | $60.00 | - | $60.00 | $157.33 |
| CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 | $ 34.37 | $2.23 | 14.39% | $0.32 | $56.00 | - | $56.00 | $130.32 |
| CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS | $ 37.86 | $5.03 | 11.52% | $0.58 | $85.02 | - | $85.02 | $283.94 |
| CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS | $ 38.42 | $4.49 | 11.52% | $0.52 | $77.00 | - | $77.00 | $229.40 |
| Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer | $ - | $0.00 | 0.00% | $0.00 | $21.20 | $ (4.85) | $21.20 | $182.03 |
| Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day | $ - | $23.91 | 0.00% | $0.00 | $28.03 | $ (0.96) | $28.03 | $35.03 |
| CCS Dave Johnston 4 (costs on post retrofit basis) | $ - | $11.40 | 11.52% | $1.31 | $82.84 | $ (160.13) | $ (77.29) | $ (487.20) |
| CCS Hunter 1-3 (costs on post retrofit basis) | $ - | $9.73 | 11.52% | $1.12 | $70.24 | $ (160.13) | $ (89.89) | $ (565.96) |
| CCS Huntington 1&2 (costs on post retrofit basis) | $ - | $9.63 | 11.52% | $1.11 | $71.09 | $ (160.13) | $ (89.04) | $ (562.82) |
| CCS Jim Bridger 3&4 (costs on post retrofit basis) | $ - | $10.57 | 11.52% | $1.22 | $70.90 | $ (160.13) | $ (89.23) | $ (554.00) |
| CCS Wyodak (costs on post retrofit basis) | $ - | $11.69 | 11.52% | $1.35 | $87.70 | $ (160.13) | $ (72.43) | $ (459.16) |
| Small Modular Reactor or Advanced Reactor, Moderate Technology Case | $ - | $9.74 | 0.00% | $0.00 | $82.73 | $ (20.29) | $62.44 | $448.80 |
| Goshen | $ - | $9.74 | 0.00% | $0.00 | $83.93 | $ (20.29) | $63.64 | $458.27 |
| Wasatch Front | $ - | $9.74 | 0.00% | $0.00 | $83.93 | $ (22.29) | $61.64 | $443.88 |
| Wyoming East | $ - | $9.74 | 0.00% | $0.00 | $82.13 | $ (22.29) | $59.85 | $429.73 |
| Small Modular Reactor or Advanced Reactor, Advanced Technology Case | $ - | $8.74 | 0.00% | $0.00 | $59.58 | $ (22.29) | $37.29 | $259.26 |
| Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage | $ - | $10.72 | 0.00% | $0.00 | $90.99 | $ (20.29) | $70.71 | $508.18 |
| Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage | $ - | $9.61 | 0.00% | $0.00 | $65.53 | $ (22.29) | $43.24 | $300.62 |
| Large Light Water Reactor, Moderate Technology Case | $ - | $9.38 | 0.00% | $0.00 | $73.09 | $ (20.29) | $52.80 | $374.94 |
| Large Light Water Reactor, Advanced Technology Case | $ - | $7.88 | 0.00% | $0.00 | $58.83 | $ (22.29) | $36.55 | $257.87 |
| Near Field Enhanhanced Geothermal System (NF-EGS) Binary | $ - | $0.00 | 0.00% | $0.00 | $96.89 | $ (23.46) | $73.43 | $514.59 |
| Southern OR | $ - | $0.00 | 0.00% | $0.00 | $108.42 | $ (23.46) | $84.96 | $595.43 |
| Wasatch Front | $ - | $0.00 | 0.00% | $0.00 | $96.89 | $ (25.77) | $71.12 | $498.40 |

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

## Table 7.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

| Resource Description | Total Resource Cost ($/MWh) | Credits | | |
|---|---|---|---|---|
| | | Tax Credits ($/MWh) (ITC already applied) | Total Resource Cost with PTC / ITC Credits ($/MWh) | Total Fixed Cost with Tax Credit ($/kW-yr) |
| PV, 20 MW, Class 1-10 | $65.11 | $ (25.15) | $39.96 | $95.69 |
| Portland North Coast | $76.45 | $ (25.15) | $51.30 | $110.04 |
| Southern OR | $66.54 | $ (25.15) | $41.39 | $106.20 |
| Walla Walla | $69.74 | $ (25.15) | $44.59 | $101.40 |
| Goshen | $64.59 | $ (25.15) | $39.44 | $96.03 |
| Wasatch Front | $61.38 | $ (27.63) | $33.75 | $85.73 |
| Wyoming East | $64.79 | $ (27.63) | $37.16 | $89.42 |
| PV, 200 MW, Class 1-10 | $44.24 | $ (25.15) | $19.09 | $45.72 |
| Portland North Coast | $51.72 | $ (25.15) | $26.57 | $56.99 |
| Southern OR | $44.87 | $ (25.15) | $19.72 | $50.59 |
| Walla Walla | $47.32 | $ (25.15) | $22.17 | $50.41 |
| Goshen | $43.86 | $ (25.15) | $18.71 | $45.54 |
| Wasatch Front | $41.71 | $ (27.63) | $14.08 | $35.76 |
| Wyoming East | $44.02 | $ (27.63) | $16.40 | $39.46 |
| PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case | $60.88 | $ (27.63) | $33.25 | $79.62 |
| PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case | $41.42 | $ (27.63) | $13.80 | $33.03 |
| Wind Class 1-10, 20 MW | $80.60 | $ (23.46) | $57.14 | $145.49 |
| Portland North Coast | $102.14 | $ (23.46) | $78.68 | $171.70 |
| Southern OR | $106.14 | $ (23.46) | $82.68 | $182.40 |
| Walla Walla | $104.46 | $ (23.46) | $81.00 | $164.12 |
| Goshen | $69.45 | $ (23.46) | $45.99 | $138.03 |
| Wasatch Front | $70.08 | $ (25.77) | $44.31 | $130.77 |
| Wyoming East | $69.41 | $ (25.77) | $43.64 | $127.01 |
| Wind Class 1-6, 200 MW | $42.12 | $ (23.46) | $18.66 | $56.18 |
| Portland North Coast | $41.47 | $ (23.46) | $18.01 | $59.36 |
| Southern OR | $47.92 | $ (23.46) | $24.46 | $72.97 |
| Walla Walla | $45.68 | $ (23.46) | $22.22 | $63.43 |
| Goshen | $48.49 | $ (23.46) | $25.03 | $66.38 |
| Wasatch Front | $47.93 | $ (25.77) | $22.16 | $59.04 |
| Wyoming East | $34.60 | $ (25.77) | $8.83 | $31.90 |
| Wind Class 7, 200 MW | $43.59 | $ (23.46) | $20.13 | $60.59 |
| Offshore, Wind Class 12 | $186.38 | $ (32.72) | $186.38 | $514.98 |
| Southern OR | $138.33 | $ (24.88) | $138.33 | $593.07 |
| Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case | $75.95 | $ (25.77) | $50.18 | $127.76 |
| Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case | $39.54 | $ (25.77) | $13.77 | $41.47 |
| Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case | $40.94 | $ (25.77) | $15.17 | $45.68 |
| Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case | $49.06 | $ (11.74) | $49.06 | $362.89 |

## Table 7.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

| Resource Description | Variable O&M | Credits | |
|---|---|---|---|
| | O&M ($/MWh) | Tax Credits ($/MWh) (ITC already applied) | Total Fixed Cost with Tax Credit ($/kW-yr) |
| Ion, 4-hour, 20 MW[1] | $0.00 | $ (32.40) | $140.22 |
| Ion, 4-hour, 200 MW[1] | $0.00 | $ (27.77) | $120.34 |
| Portland North Coast | $0.00 | $ (29.44) | $125.15 |
| Southern OR | $0.00 | $ (29.99) | $126.75 |
| Walla Walla | $0.00 | $ (28.61) | $122.74 |
| Goshen | $0.00 | $ (28.33) | $121.94 |
| Wasatch Front | $0.00 | $ (38.14) | $108.60 |
| Wyoming East | $0.00 | $ (36.66) | $105.93 |
| Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1] | $0.00 | $ (23.69) | $209.16 |
| Portland North Coast | $0.00 | $ (25.11) | $217.37 |
| Southern OR | $0.00 | $ (25.59) | $220.11 |
| Walla Walla | $0.00 | $ (24.40) | $213.27 |
| Goshen | $0.00 | $ (24.17) | $211.90 |
| Wasatch Front | $0.00 | $ (32.54) | $189.10 |
| Wyoming East | $0.00 | $ (31.27) | $184.54 |
| Ion, 4-hour, 1000 MW[1] | $0.00 | $ (27.05) | $116.47 |
| Gravity Battery, 4-hour, 1000 MW | $0.00 | $ (33.10) | $109.45 |
| Wasatch Front | $0.00 | $ (34.09) | $111.22 |
| Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW | $0.00 | $ (24.62) | $183.58 |
| Adiabatic CAES, 500 MW, 4000 MWh | $2.60 | $ (27.92) | $182.29 |
| 100-hour Iron Air | $0.00 | $ (37.40) | $154.47 |
| Portland North Coast | $0.00 | $ (29.72) | $189.65 |
| Wasatch Front | $0.00 | $ (38.52) | $158.22 |
| Pumped Hydro, Two New Reservoirs, 4-hour | $0.58 | $ (33.01) | $118.52 |
| Pumped Hydro, Two New Reservoirs, 10-hour | $0.58 | $ (18.40) | $157.02 |
| Portland North Coast | $0.58 | $ (19.51) | $164.81 |
| Southern OR | $0.58 | $ (19.87) | $167.40 |
| Goshen | $0.58 | $ (18.77) | $159.61 |
| Wasatch Front | $0.58 | $ (25.28) | $136.70 |
| Wyoming East | $0.58 | $ (24.30) | $132.41 |
| Pumped Hydro, One New Reservoir, 4-hour | $0.58 | $ (31.89) | $115.21 |
| Pumped Hydro, One New Reservoir, 10-hour | $0.58 | $ (15.65) | $136.65 |
| Pumped Thermal Energy Storage, 10-hour | $0.70 | $ (34.12) | $211.57 |
| Pumped Thermal Energy Storage, 24-hour | $0.70 | $ (63.70) | $390.51 |

1Assumed co-located

**Table 7.12 - Glossary of Terms Used in the Supply-Side Resource Tables**

| Term | Description |
|---|---|
| Fuel | Primary fuel used for electricity generation or storage. |
| Resource | Primary technology used for electricity generation or storage. |
| Elevation (afsl) | Average feet above sea level for the proxy site for the given resource. |
| Net Capacity (MW) | For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition. |
| Resource Availability Year | The earliest year the Company would sign a contract for a Resource being studied in this IRP. If available prior to the development of this database, this defaults to IRP year. |
| Total Implementation Time | Number of years necessary to implement all phases of resource development and construction after signing a contract to build the Resource: permitting (e.g., air, land, water, and wildlife), maintenance contracts, owner's engineering, construction, testing, and grid interconnection. |
| Commercial Operation Year | Year when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time. |
| Design Life (years) | Average number of years the resource is expected to be "used and useful." |
| Base Capital ($/kW) | Total capital expenditure in dollars per kilowatt ($/kW) for the development and construction of a Resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit, and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, and owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes, and escalation during construction, if applicable). |
| Var O&M ($/MWh) | Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance, and fired hour fees in dollars per megawatt hour ($/MWh). |
| Fixed O&M ($/kW-year) | Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, and training. |
| Demolition Cost ($/kW) | Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW). |
| Full Load Heat Rate HHV (Btu/kWh) | Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis. |
| Efficiency | Typical operational round-trip efficiency of energy storage of alternating current (AC) energy delivered to the grid divided by AC energy stored from the grid. |

| Term | Description |
|---|---|
| EFOR (%) | Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given Resource at the given site. |
| POR (%) | Estimated Planned Outage Rate for a given Resource at the given site. |
| Water Consumed (gal/MWh) | Average amount of water consumed by a Resource for make-up, cooling water make-up, inlet conditioning and pollution control. |
| SO2 (lbs/MMBtu) | Expected permitted level of sulfur dioxide (SO2) emissions in pounds of sulfur dioxide per million Btu of heat input. |
| NOx (lbs/MMBtu) | Expected permitted level of nitrogen oxides (NOx) (expressed as NO2) in pounds of NOx per million Btu of heat input. |
| Hg (lbs/TBtu) | Expected permitted level of mercury emissions in pounds per trillion Btu of heat input. |
| CO2 (lbs/MMBtu) | Pounds of carbon dioxide (CO2) emitted per million Btu of heat input. |

**Table 7.13 - Glossary of Acronyms Used in Chapter 7**

| Acronyms | Description |
|---|---|
| ACAES | Adiabatic Compressed Air Energy storage |
| AFSL | Average Feet (Above) Sea Level |
| ATB | Annual Technology Baseline |
| CAES | Compressed Air Energy Storage |
| CCCT | Combined Cycle Combustion Turbine |
| CCS | Carbon Capture and Storage |
| CCUS | Carbon Capture, Utilization and Storage |
| CF | Capacity Factor |
| CSP | Concentrated Solar Power |
| CT | Combustion Turbine |
| DF | Duct Firing |
| DOE | United States Department of Energy |
| EIA | Energy Information Agency |
| FGD | Flue Gas Desulfurization |
| GAIN | Gateway for Accelerated Innovation in Nuclear |
| HRSG | Heat Recovery Steam Generator |
| ICE | Internal Combustion Engine (reciprocating engine) |
| IGCC | Integrated Gasification Combined Cycle |
| ISO | International Standards Organization (Temperature = 59 degrees Fahrenheit (°F) / 15 degrees Celsius (°C), Pressure = 14.7 psia/1.013 bar) |
| Li-Ion | Lithium Ion |
| LFP | Lithium Iron Phosphate (sub-chemistry of lithium-ion) |
| MW | Megawatt |
| NCM | Nickel Cobalt Manganese (sub-chemistry of lithium-ion) |
| NREL | National Renewable Energy Laboratory |
| OEM | Original Equipment Manufacturer |
| OSTI | Office of Scientific and Technical Information |

| | |
|---|---|
| OSW | Offshore Wind |
| PCCC | Post Combustion CO2 Capture |
| PEM | Proton Exchange Membrane |
| PPA | Power Purchase Agreement |
| PC CCUS | Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage |
| PHES | Pumped Hydro Energy Storage |
| PV Poly-Si | Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers |
| Recip | Reciprocating Engine |
| RTE | Round Trip Efficiency (typical operational AC to AC energy storage efficiency) |
| SCCT | Simple Cycle Combustion Turbine |
| SCR | Selective catalytic reduction |
| STG | Steam turbine generator |

## Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.2 through Table 7.11. For all technology that is included in the 2024 NREL ATB, the ATB costs were used. For incremental items, a percentage difference between the technology with and without the incremental resource was used. Where data is available for an advanced technology innovation scenario[24], there is a resource row for that scenario.

**Internal Combustion Engine x4, renewable biofuel, with SCR & fuel tank** – This is a reciprocating internal combustion engine (RICE) power plant based on four large-scale engines, that are assumed to burn a liquid renewable biofuel like biodiesel or renewable diesel. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW."[25] It is presented in the IRP as a 20 MW resource to meet Oregon's regulatory requirements for distributed generation resources, under the assumption that it could be derated to meet the requirements. The 24-hour fuel tank was added to the 2020 EIA Report's resource based on available market information on in-ground fuel tanks.[26]

**Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4** – This is "four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also

[24] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[25] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[26] See Appendix M, stakeholder feedback form #59 (Renewable Northwest).

equipped with burners designed to reduce the CT's emission of $NO_X$. Included are SCR units for further reduction of $NO_X$ emissions and CO catalysts for further reduction of CO emissions."[27]

**Natural Gas, SCCT Frame "F" x 1, with SCR** – This is "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of $NO_X$."[28] Although the 2020 EIA Report does not include an SCR for this resource, to be on par with the other IRP resources, the approximate cost of an SCR was added based on the cost difference on a percentage basis from previous IRP's.

**Natural Gas, CCCT "H", 1x1, DF, with SCR** – This is "one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross, and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW."[29]

**Natural Gas, CCCT "H", 2x1, DF, with SCR** – This is "a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW."[30]

**Natural Gas, Δ for adding 95% CCS** – This option reflects incremental changes for a greenfield "power plant w/ commercially available solvent-based post combustion $CO_2$ capture (PCCC) designed for 95% capture."[31] The 95% option was chosen because that is the most economic option available in the NREL ATB that meets the EPA 111 regulations.

**Natural Gas, Δ for CT Brownfield construction** – This option reflects incremental changes for construction of a resource at an existing powerplant site with the same technology.

**Hydrogen, Δ for 100% Hydrogen burning capability** – This option reflects incremental changes for a CT to burn a mixture of fuel up to 100% hydrogen.

**Hydrogen, Δ for Hydrogen storage, cavern, 80 bar, 1 week** – This option reflects incremental changes for storing hydrogen underground in a solution-mined geologic salt dome. Hydrogen gas

[27] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[28] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[29] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[30] Ibid 17
[31] 2024 ATB Excel Workbook, available at https://atb.nrel.gov/electricity/2024/data.

is compressed and stored at ambient temperature in at elevated pressure (70-190 bar). Salt domes only exist in a limited number of locations (~2000 salt caverns in North America with an average capacity of $10^5$-$10^6$ $m^3$). There are at least two salt domes under development within PacifiCorp's area of operation. This assumes a "600 tons per day (TPD) pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume."[32] In addition to the Pathways to Commercial Liftoff: Clean Hydrogen (Clean Hydrogen Liftoff Report), the Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan[33] was used for cost and technical data.

**Hydrogen, Δ for Hydrogen storage, tanks, 500 bar, 24-hour** – This option reflects incremental changes for storing hydrogen in tanks constructed above ground. "$H_2$ gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of $H_2$ at room temperature. Assumes 950 kg stored at 500 bar with 1 cycle per week."[34]

**Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day** – Also known as polymer electrolyte membrane, including balance of plant (BOP) costs, the "electrolyzer design is intended to represent the current state-of-the-art (2022) stacks with respect to catalyst loadings (3 milligrams per square centimeter [mg/cm2] total platinum group metal [PGM] loading) and material specifications."[35] Data from the DOE Hydrogen and Fuel Cells Program Record[36] was also used in the development of this resource.

**Coal, CCS**– These are retrofits of an existing conventional coal-fired boiler and steam-turbine generator resources with amine based post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCS would remove 95 percent of the carbon dioxide and would provide reductions in other emissions.[37]

**Storage, Lithium Ion Battery** – This is lithium-ion batteries rated at 20 and 200 MW capacities with 4-hour duration. The 20 MW option uses the ATB's "Commercial Battery" data, while the 200 MW option uses the ATB's "Utility-Scale" data.

[32] Pathways to Commercial Liftoff: Clean Hydrogen, U.S. Department of Energy, Office of Technology Transitions: Hannah Murdoch; Office of Clean Energy Demonstrations: Jason Munster; Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi; Argonne National Laboratory: Amgad Elgowainy; National Renewable Energy Laboratory: Michael Penev, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf

[33] Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan, Dr. Sunita Satyapal, U.S. Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-multi-year-program-plan

[34] ibid 20

[35] Badgett, Alex, Joe Brauch, Amogh Thatte, Rachel Rubin, Christopher Skangos, Xiaohua Wang, Rajesh Ahluwalia, Bryan Pivovar, and Mark Ruth. 2024. *Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87625. https://www.nrel.gov/docs/fy24osti/87625.pdf.

[36] David Peterson, James Vickers, Dan DeSantis, *Hydrogen Production Cost From PEM Electrolysis – 2019*, February 3, 2020, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

[37] Carbon capture costs and parameters were the subject of discussion and feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #25 (NP Energy, LLC).
See Appendix M, stakeholder feedback form #44 (Sierra Club).

**Storage, Δ double duration** – This option reflects incremental changes for doubling the duration of a battery energy storage resource, modifiers on this row must be applied to the data in the appropriate resource row. Appropriate resources are limited to those utilizing lithium-ion energy storage, including lithium-ion energy storage collocated with other resources.

**Storage, Δ for Co-Located Energy Storage** – This option reflects incremental changes for lithium-ion energy storage collocated with another resource, modifiers on this row must be applied to the appropriate energy storage data.

**Storage, Gravity Battery, 4-hour, 1000 MW** – This is an estimate for any technology that uses the potential energy differential of a large mass but excludes pumped hydro. Pumped hydro is a well-established technology and because of this there is more accurate data available for pumped hydro. Examples include dense weights lifted vertically, heavy rail cars moved up and down a steep track, or a piston displacing a fluid vertically. Costs were escalated from the 2023 IRP.

**Storage, Adiabatic CAES –** Compressed air energy storage (CAES) system consists of an air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. Only the system sizes of 500 MW are included because that size was the lowest cost per kWh in the 2023 IRP. The air storage reservoir is an engineered tank. "Adiabatic" conserves heat during storage and discharge and means the system does not burn natural gas to generate power.

**Storage, Pumped Hydro, Two New Reservoirs** – Also known as closed-loop pumped hydro, this technology pumps and releases water between a higher and a lower reservoir. It is modeled as a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 1 data.

**Storage, Pumped Hydro, One New Reservoirs** – Also known as an open-loop system, this technology pumps and releases water between a higher reservoir and a lower natural water body, usually a river. It is modeled as a nominal 400 MW PHES system using both natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 5 data.

**Storage, 100-hour Iron Air** – This is a low capital cost battery option with the trade off a low round trip efficiency. "While discharging, the battery breathes in oxygen from the air and converts iron metal to rust. While charging, the application of an electrical current converts the rust back to iron and the battery breathes out oxygen."[38]

**Storage, Pumped Thermal Energy Storage** – This is a system using a storage tank of high temperature fluid to store energy. A resistive heater converts electric energy to heat energy in the

[38] https://formenergy.com/technology/battery-technology/

fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator.

**Solar, PV, Class 1 - 10** – This is ATB PV Class 1 through 10 (20 MW or 200 MW) solar photovoltaic resources using crystalline silica solar panels in a single axis tracking system. The 20 MW option uses the ATB's "Commercial" data, while the 200 MW option uses the ATB's "Utility-Scale" data. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

**Wind, Wind Class 1-10, 20 MW** – This is ATB "Distributed Wind, Large Turbine Technology Class." It is a wind resource of 1,500 kW turbines with 107-meter rotor diameter and 80-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

**Wind, Wind Class 1-6, and 7200 MW** – This is ATB Land-Based Wind technology configuration T1. It is a wind resource of 34 x 6 MW turbines with 170-meter rotor diameter and 115-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

**Wind, Wind Class 7, 200 MW** – This is the same as wind classes 1- 6, but different wind conditions and cost data.

**Wind, Offshore, Wind Class 12** – This is ATB "Floating Offshore Wind." It is a wind resource of 12 MW turbines with 216-meter rotor diameter and 137-meter hub height. Wind Class 12 represents the wind conditions off the coast of northern California and southern Oregon. The ATB lists a net capacity factor of 47% for Offshore Wind Class 12.

**Nuclear, Small Modular Reactor or Advanced Reactor** – This is a conceptual technology that could be a small modular reactor or small advanced reactor. "Modular" refers to a reactor that can be built off site and easily transported to the installation location, however scale of economy requires multiple modular reactors to share support facilities at a single powerplant site. Data is from the ATB and relies heavily on a DOE Office of Scientific and Technical Information, Gateway for Accelerated Innovation in Nuclear report[39] ("OSTI GAIN Report").

**Nuclear, Δ for nuclear integrated thermal storage, 5 hours** - This option reflects incremental changes for a system using a storage tank of high temperature fluid. To store energy, heat from a nuclear reactor is transferred in a heat exchanger to the storage fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator. This method eliminates the resistive heater losses in the stand-alone thermal storage, and therefore has a much higher RTE.

**Nuclear, Large Light Water Reactor** – This is a modern dual unit reactor similar to most of the existing utility reactors in the United States. Data is from the ATB and relies heavily on the OSTI GAIN Report.

[39] Abdalla Abou-Jaoude, Levi M Larsen, Nahuel Guaita, Ishita Trivedi, Frederick Joseck, and Christopher Lohse, Idaho National Laboratory; Edward Hoffman and Nicolas Stauff. Argonne National Laboratory; Koroush Shirvan, Massachusetts Institute of Technology; Adam Stein, Breakthrough Institute; Gateway for Accelerated Innovation in Nuclear (GAIN); *Meta-Analysis of Advanced Nuclear Reactor Cost Estimations*, July 2024, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

**Geothermal, Near Field Enhanced Geothermal System (NF-EGS) Binary** – This is the ATB geothermal plant utilizing a 175°C thermal resource with 1.5 km wells and production well flow rates of 60 kg/s.[40]

## Locational Modifiers and Selected Cost Forecasts

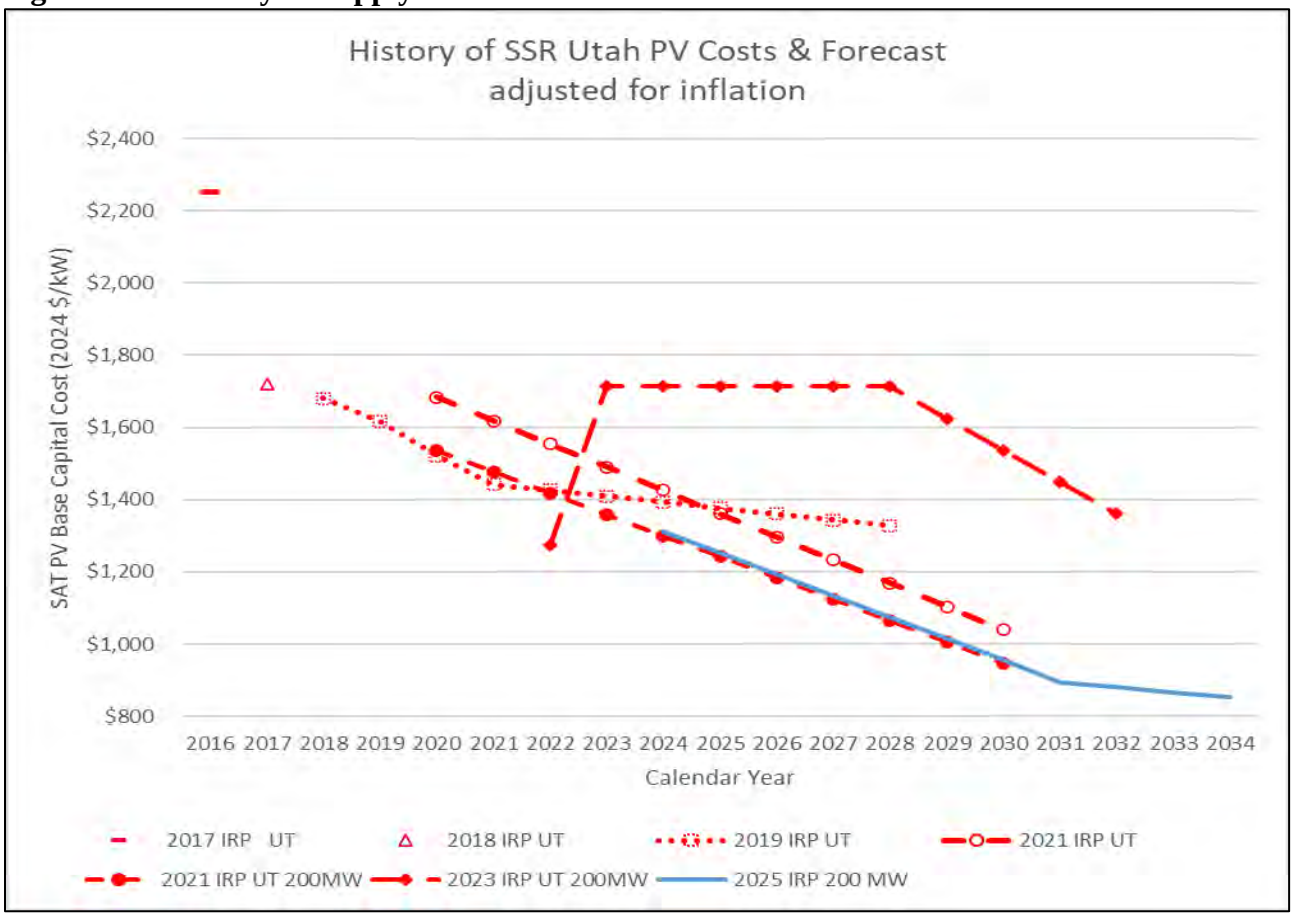
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options in the supply-side resource table. For any resource option without a technology specific cost forecast, escalation is assumed to be level. These locational modifiers and cost forecasts are applied in PLEXOS. Cost forecast histories for selected resource types are shown in the following sections.

**PV Cost Forecast History**

Figure 7.1 shows a history of capital cost forecasts used in the supply-side resource table for PV resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost estimates for solar resources are based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is essentially the same as the trend line of the 2021 IRP.

[40] Geothermal modeling was the subject of stakeholder feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

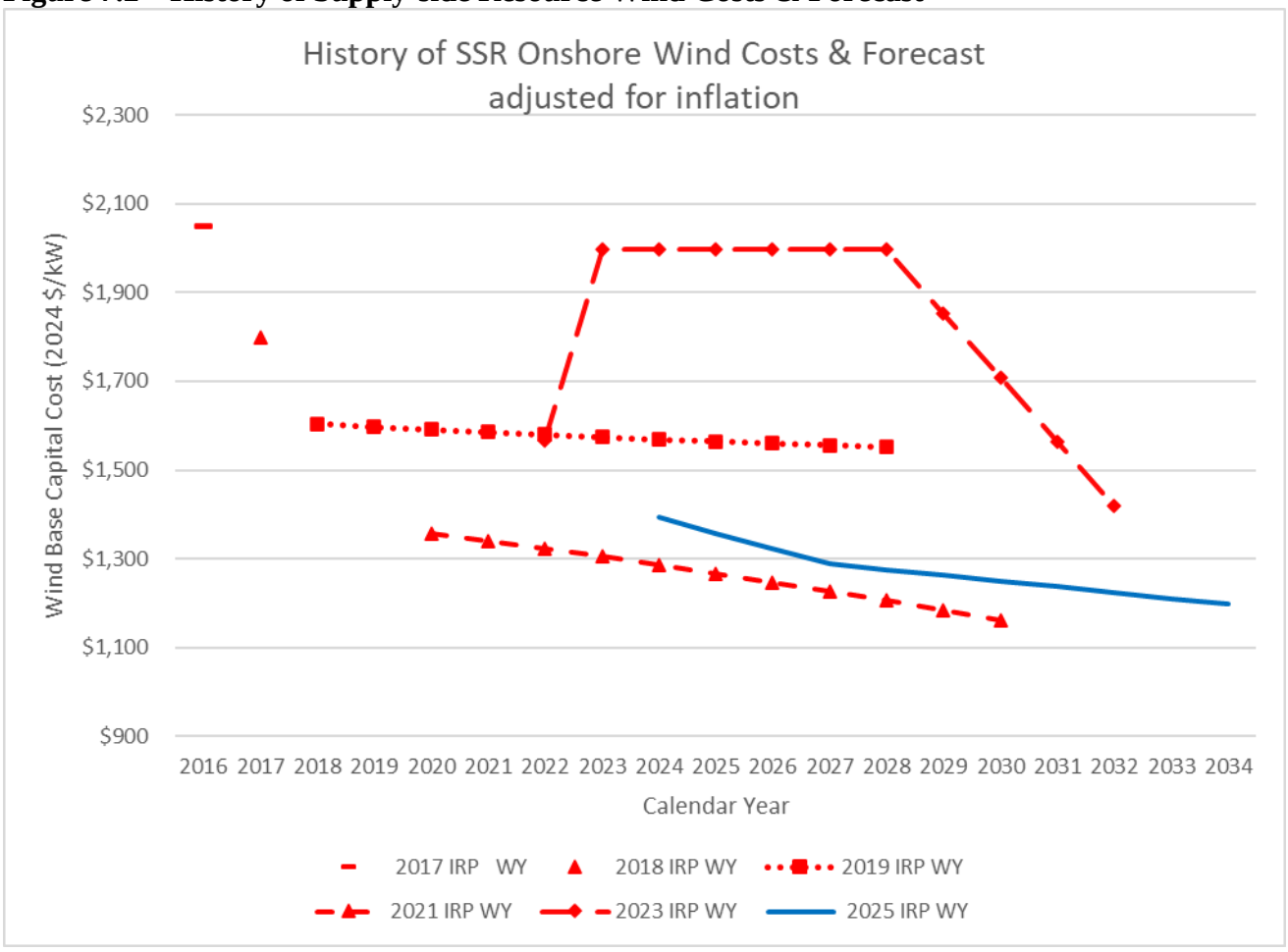
**Figure 7.1 – History of Supply-side Resource PV Cost & Forecast**




**Wind Cost Forecast History**

Figure 7.2 shows a history of capital cost forecasts used in the supply-side resource table for resources in Wyoming from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for wind resources is based on the ATB forecast. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is close to the trend line of the 2021 IRP.

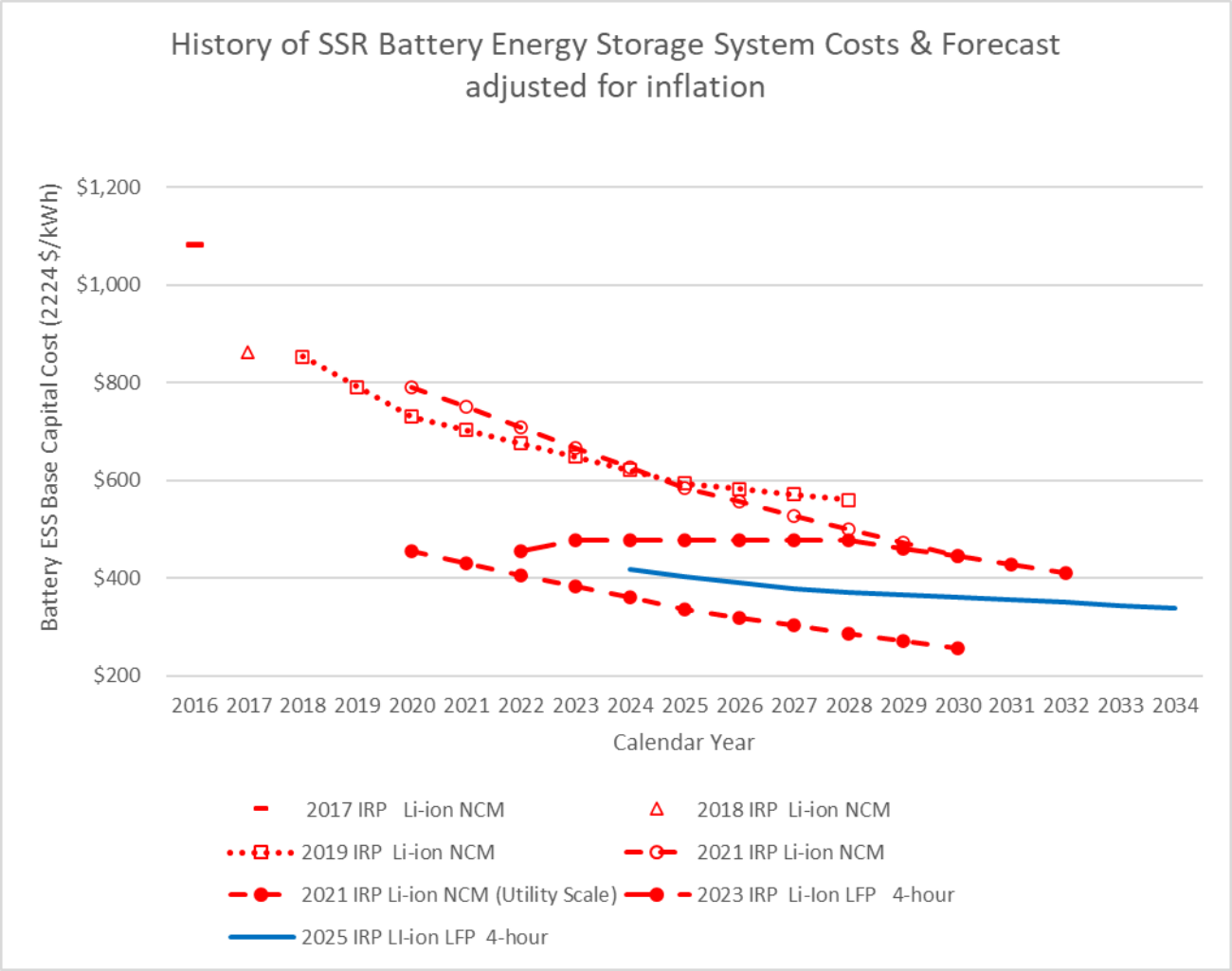
**Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast**




**Energy Storage**

Figure 7.3 shows a history of capital cost forecasts used in the supply-side resource table for BESS resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for BESS resources is based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been partially mitigated by federal policy changes and the forecast costs are about midway between the less expensive 2021 IRP and the more expensive 2023 IRP.

**Figure 7.3 – History of Battery Energy Storage System Costs & Forecast**




***Utility-scale Energy Storage Resources***

PacifiCorp has contracted for the following utility-scale energy storage resources:

- Faraday solar and storage (525 MW solar, 150 MW battery storage with 4-hour duration) is a project supporting customer clean energy goals under Utah Schedule 34.
- Green River solar and storage (400 MW solar, 400 MW battery storage with 4-hour duration) is a project that was originally part of the final shortlist in the 2020 All-Source Request for Proposals. An amendment to the contract expanded the battery from 200 MW with two-hour duration to 400 MW with four-hour duration.
- Dominguez Grid (200 MW battery storage with four-hour duration) is a stand-alone energy storage resource.
- Enterprise/Escalante/Granite Mountain East/Iron Springs storage: each of these contracts is an 80 MW battery storage resource with four-hour duration. Battery storage is being added at existing solar resources and will use surplus interconnection. A surplus interconnection allows for resources to be added at any existing interconnection location so long as the total output to the grid is kept within the existing interconnection capacity.

As a result of the contracts described above, PacifiCorp expects to bring more than one gigawatt of energy storage resources online by the summer of 2026.

**Comparison of Lazard's Levelized Cost of Energy Analysis-Version 17 (LCOE+ 17)[41] and NREL's 2024 ATB[42]**

Lazard's LCOE+ 17 and the NREL ATB both inform stakeholders about the economic viability of different energy sources, but they differ in scope, methodology, and the specifics of their cost assumptions. Each report is assumed to use a consistent but distinct methodology across all technologies, with technology specific nuances treated fairly. Table 7.14 provides a side-by-side comparison of pertinent information in the two reports.

Lazard's LCOE+ 17 cost assumptions are based on a standardized financial model with fixed debt and equity costs. The analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost, resulting in an after-tax weighted average cost of capital (WACC) of 7.7%.

NREL's ATB offers a range of financial assumption options to reflect different market conditions and provide a more comprehensive view of potential costs.

**Table 7.14 – Comparison of Lazard LCOE+ and NREL ATB**

| | Lazard LCOE+ 17 | NREL ATB |
|---|---|---|
| Levelized Cost of Energy (LCOE) | Historic Ranges & Averages | Historic and future "Technology Advancement Scenarios" options |
| Levelized Cost of Storage (LCOS) | Yes | No |
| Levelized Cost of Hydrogen (LCOH) | Yes | No |
| Finance Assumptions | No | Yes |
| Tax Credits | Yes | Optional |
| Capital Cost | Yes, but not clearly defined | "Capital Expenditure" (CAPEX) |
| Construction Cost | Assumed to be included | Yes |
| Overnight Capital Cost | No | Yes |
| Grid Connection Cost | Not clear | Yes |
| Construction Finance Factor | No | Yes |
| Construction Cashflow Curve | No | No |
| Weighted Average Cost of Capital | Yes | Yes |
| Fixed O&M (FOM) | Yes | Yes |
| Variable O&M (VOM) | Yes | Yes |
| Capacity Factor (CF) | Yes | Yes |
| Facility Net Power Capacity | Yes | Yes |
| Heat Rate | Yes | Yes |

[41] Lazard Levelized Cost of Energy +, June 2024, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf
[42] https://atb.nrel.gov/electricity/2024/index

| | | |
|---|---|---|
| Construction Time | Yes | Yes |
| Design Life | Yes | Yes |
| Energy Storage Duration | Yes | Yes |
| Energy Storage Round Trip Efficiency (RTE) | Yes | Yes |
| Energy Storage Degradation | Yes | Included in FOM |
| Regional Resolution Level | Regional markets, including CAISO but not WECC | Select cites in each state, per referenced reports |
| Regional Adjustment Factors | No | Included in referenced reports |
| Effective Load Carrying Capability (ELCC) Analysis | Yes | No |
| Demolition Costs | No | No |
| Outage Rates, Forced and Planned | Assumed to be included in CF | Assumed to be included in CF |
| References or Bibliography | No | Yes |

The costs reported by Lazard and NREL can differ due to variations in their methodologies and assumptions. Lazard's LCOE+ 17 tends to provide a more standardized comparison across technologies, which can be useful for high-level decision-making. In contrast, NREL's ATB offers a more detailed and nuanced view, considering different scenarios and market conditions.
Reasons for Cost Differences:

- Methodological Differences: Lazard uses a fixed financial model, while NREL incorporates a range of scenarios and assumptions, leading to different cost estimates.
- Scope of Analysis: Lazard focuses on a high-level comparison of technologies, whereas NREL provides detailed data for specific scenarios and market conditions.
- Financial Assumptions: Differences in debt and equity costs, as well as WACC, can lead to variations in the reported costs.
- Technology Assumptions: NREL's ATB includes projections for future technology advancements, which can result in lower cost estimates compared to Lazard's more conservative approach.

In summary, while both Lazard's LCOE+ 17 and NREL's ATB provide valuable insights into the costs of energy technologies, their differences in scope, methodology, and assumptions can lead to varying cost estimates. Understanding these differences is crucial for stakeholders to make informed decisions about energy investments.

# Demand-Side Resources

## Resource Options and Attributes

**Source of Demand-Side Management Resource Data**
PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2025-2044, which provided DSM resource opportunity estimates for the 2025 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of

the size, type, location and cost of demand-side resources.[43] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

***Demand-Side Management Supply Curves***

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g., products and quantities) based on each resource's competitiveness against alternative resource options.[44] Due to the timing of the 2025 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2025 DSM program acquisition targets. To ensure that the 2025 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2025. In 2026, energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period.
- Persistence of resource savings (e.g., energy efficiency equipment measure lives).
- Seasonal availability and hours available (e.g., irrigation load control programs).
- The hourly shape of the resource (e.g., load shape of the resource).
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

<u>Demand Response: DSM Capacity Supply Curves</u>

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2025, PacifiCorp has launched and expanded several demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2025.

[43] The 2025 Conservation Potential Study is available on PacifiCorp's IRP Support & Studies web page: www.pacificorp.com/energy/integrated-resource-plan/support.html.

[44] Demand-side management modeling and methodology was a frequent topic of discussion in the 2025 IRP public input meeting series and in stakeholder feedback forms.
See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
See Appendix M, stakeholder feedback form #45 (Utah Clean Energy).

**Table 7.15 – Demand Response Existing and Planned Programs**

| Product | State | Existing or Planned Offering |
|---|---|---|
| Res – HVAC DLC | UT | Existing |
| Res – HVAC DLC | OR, WA | Planned |
| Res – EV Load Control | OR, WA, UT | Planned |
| Res – Battery DLC | OR, WA | Planned |
| Res – Battery DLC | ID, UT | Existing |
| C&I – Battery DLC | ID, UT | Existing |
| C&I – Third Party | OR, WA, UT | Existing |
| C&I – Third Party | ID | Planned |
| Ag – Irrigation DLC | UT, ID, OR, WA | Existing |

Table 7.16 and Table 7.16 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2025 CPA.[45] Potential shown is incremental to the existing DSM resources identified in Table 7.17. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2025. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2026. New program offerings are assumed to be available in 2026 accounting for the time required for program design, regulatory approval, vendor selection, procurement, and implementation.

**Table 7.16 – Demand Response Program Attributes West Control Area,[46]***

| Product | Summer | | Winter | |
|---|---|---|---|---|
| | 20-Year Potential (MW) | Average Levelized Cost ($/kW-yr) | 20-Year Potential (MW) | Average Levelized Cost ($/kW-yr) |
| Res – EV DLC | 15.1 | $412 | 15.1 | $412 |
| Res – DLC of Smart Home | 0.1 | $1,306 | 0.1 | $686 |
| Res – HVAC DLC | 17.4 | $175 | 81.7 | $73 |
| Res – Pool Pump DLC | 0.2 | $742 | 0.1 | $1,956 |
| Res – Water Heater DLC | 2.7 | $134 | 4.0 | $90 |
| Res – Smart Thermostat | 40.2 | $37 | 28.9 | $29 |
| Res – Grid Interactive Water Heaters | 14.6 | $97 | 24.5 | $66 |
| Battery DLC | 6.1 | $31 | 4.9 | $30 |
| C&I – Third Party | 8.5 | $46 | 12.4 | $54 |
| Ag – Irrigation DLC | 1.8 | $24 | 0.0 | $0 |

* Average levelized cost weighted by the 20-year cumulative potential in each state

[45] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
[46] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

**Table 7.17 – Demand Response Program Attributes East Control Area,[47]***

| Product | Summer | | Winter | |
|---|---|---|---|---|
| | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) |
| Res – EV DLC | 24.8 | $416 | 24.8 | $416 |
| Res – DLC of Smart Home | 0.1 | $1,601 | 0.3 | $772 |
| Res – HVAC DLC | 234.2 | $158 | 141.3 | $272 |
| Res – Pool Pump DLC | 0.2 | $834 | 0.1 | $2,199 |
| Res – Water Heater DLC | 12.8 | $175 | 17.5 | $117 |
| Res – Smart Thermostat | 90.4 | $38 | 50.2 | $94 |
| Res – Grid Interactive Water Heaters | 1.1 | $209 | 2.0 | $139 |
| Battery DLC | 65.3 | $36 | 65.2 | $41 |
| C&I – Third Party | 66.6 | $52 | 72.7 | $50 |
| Ag – Irrigation DLC | 19.1 | $29 | 0.0 | $0 |

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2025 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[48]
- **Measure:**
  - 120 residential measures
  - 146 commercial measures
  - 105 industrial measures
  - 19 irrigation measures

- **Facility type:**[49]
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types

[47] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

[48] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

[49] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in Volume 1 of the 2025 CPA.

- Two irrigation facility type

The 2025 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e., incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the 20-year CPA planning horizon totaled approximately 15.1 million MWh.[50] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 12.8 million MWh for all five states. The technical achievable potential for all six states, i.e., including Oregon, for modeling consideration is 17.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated just over 50,500 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 21-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[51]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2025 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency

[50] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

[51] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

resource supply curves. Table 7.18 shows the 21-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure's temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity ($/kW-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are "free." These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

**Table 7.18 – 2045 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)**

| Bundle | California | Idaho | Oregon | Utah | Washington | Wyoming |
|---|---|---|---|---|---|---|
| Cooling Measures | 34,469 | 42,040 | 609,077 | 1,282,306 | 102,772 | 108,946 |
| Heating Measures | 28,535 | 75,471 | 870,110 | 751,888 | 197,253 | 122,268 |
| Summer Measures | 68,513 | 119,447 | 1,292,227 | 1,244,883 | 366,577 | 221,926 |
| Winter Measures | 221 | 14,417 | 103,548 | 221,229 | 3,524 | 347,464 |
| Zero Cost Temperature Dependent Measures | 18,360 | 84,725 | 295,605 | 1,550,447 | 127,775 | 84,371 |
| Zero Cost Non-Temperature Dependent Measures | 33,056 | 260,493 | 1,224,970 | 3,470,030 | 376,187 | 626,797 |

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.19)
- Stochastic risk reduction credit.[52]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only).[53]

[52] PacifiCorp develops this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

[53] The formula for calculating the $/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

**Table 7.19 – State-specific Transmission and Distribution Credits (2024$)**

| State | Transmission Deferral Value ($/kW-year) | Distribution Deferral Value ($/kW-year) | Total |
|---|---|---|---|
| California | $5.83 | $11.23 | $17.06 |
| Oregon | $5.83 | $15.65 | $21.49 |
| Washington | $5.83 | $18.93 | $24.76 |
| Idaho | $5.83 | $23.11 | $28.94 |
| Utah | $5.83 | $18.62 | $24.46 |
| Wyoming | $5.83 | $9.61 | $15.44 |

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. As in the 2023 IRP, PacifiCorp has reshaped daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For temperature dependent measures, the simulated savings are proportionate with the temperature-sensitive load across in each month, so that the highest savings occur on the highest load days in the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape. These shapes reflect measure-level annual energy savings, differentiated by state, sector, market segment, and end use. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

### Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 275 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME across the Pacific Power and Rocky Mountain Power service areas. This resulted in more than 34 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

## Transmission Resources

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation).

## Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations.

Market transactions can encompass a wide variety of product types that can be classified as either forward (entered well in advance of delivery) or spot (entered no more than a day or two before delivery). Currently, the most commonly traded forward products are for heavy load hours (HLH) and/or light load hours (LLH) and are typically for calendar quarters (e.g. "Q3" spanning July, August, and September) or individual months. Other timeframes are less common but could include super-peak products (noon to 8:00 p.m.). All the common forward market products represent undifferentiated system power supplied at a point, but forward transactions can also be based on the costs, availability, options, and/or restrictions of specific physical resources. Some examples include slices of hydropower resources, or a tolling agreement for a natural gas-fired resource.

Examples of spot market transactions include day-ahead HLH and LLH products, day-ahead hourly transactions in the CAISO market, hour-ahead products, and intra-hour products facilitated by the Western Energy Imbalance Market (EIM).

In the next few years, two changes are coming that will change the landscape of markets in both forward and spot timeframes. First, the Western Resource Adequacy Program (WRAP) requires a showing of capacity resources several months in advance of the summer and winter seasons. Current HLH and LLH market products will not count as capacity for WRAP unless the two counterparties agree to a capacity transfer, which may incur a higher cost or reduce a counterparty's willingness to sell. While contracts for physical resources would count as capacity for WRAP if the seller attests the capacity is surplus to its needs and the resource is registered in the program, it is unclear how much capacity of that sort is likely to be available, particularly as many WRAP participants all seek to become compliant. Second, CAISO's Enhanced Day-Ahead Market (EDAM) will expand day-ahead resource optimization beyond the current CAISO footprint and will impact spot market participation. While EDAM takes over much of the optimization function in the day-ahead timeframe, to prevent leaning participants will be required to pass balancing tests to ensure they bring sufficient resources to meet their load, and this may necessitate transactions ahead of the EDAM.

In past IRPs, PacifiCorp included front office transactions (FOT) as proxy resource options, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Consistent with the current WRAP rules for unspecified-source purchases, FOTs are not included in the calculation of WRAP compliance in the 2025 IRP, so forward market purchases will not count as capacity. While the 2025 IRP does not allow FOTs to meet WRAP compliance requirements, PacifiCorp expects to continue pursuing economic short-term and intermediate term market opportunities that assist with WRAP compliance and/or balancing.

Spot market purchases and sales also provide opportunities to economically balance loads and resources. The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model's hourly balancing optimization of market purchase and sales volumes against static hourly market prices.

In the EDAM and EIM, market prices are based on marginal supply and demand, so significant increases in supply are likely to reduce prices while increases in demand are likely to increase prices. When demand is high and begins to approach the limits of available supply, economic opportunities will diminish, and adequate capacity will still be needed to participate. The 2025 IRP has incorporated historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand; however, it still relies upon a static forecast of prices that do not account for portfolio selections through time. With these various factors in mind, hourly market purchase volumes have been restricted during key hours on the top five load days within each month. These restrictions apply from 4:00 p.m. to 12:00 a.m. throughout the year, and in the winter an additional restriction applies in the morning, from 4:00 a.m. to 8:00 a.m. Outside of these hours (and all day on lower load days), market purchases are allowed up to modeled transmission limits. Similarly, hourly market sales volumes have been restricted to historical levels, to avoid increasing reliance on wholesale sales at favorable prices that may not persist in an organized market.

Chapter 5 describes the relationship of front office transactions (FOTs) to reliability and WRAP compliance, and FOTs are also considered a resource. Front office transactions can be made years, quarters, or months in advance of use; however, they are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point.

Additional discussion of how FOTs are considered in the 2025 IRP, refer to Chapter 5 and Chapter 8.

# CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

## CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used PLEXOS software to produce unique resource portfolios across a range of different planning cases. Informed by the public input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 21 years.[1]
- The PLEXOS long-term (LT) model was used to generate initial portfolios and identify the resulting fixed costs. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three federal carbon dioxide ($CO_2$) policy scenarios (zero compliance requirements, a high price on $CO_2$ emissions, and compliance with current Environmental Protection Agency (EPA) $CO_2$ regulations). An additional $CO_2$ policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/current EPA regulations, medium gas/zero $CO_2$, high gas and coal/high $CO_2$, low gas/zero $CO_2$, and medium gas/social cost of greenhouse gases).
- Each initial portfolio was also evaluated in the short-term (ST) model to establish system costs over the entire 21-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- A selection of competitive "variant" portfolios was analyzed using the other four price-policy scenarios in PLEXOS modeling to evaluate how each portfolio performs under differing future market and policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from ST reporting and stochastic modeling, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, $CO_2$ emissions and other criteria.

[1] PacifiCorp's IRP is typically modeled with a 20-year planning horizon, expanded in the 2025 IRP to 21 years to accommodate a specific Washington State requirement extending through 2045. Some discussions and data graphs in the 2025 IRP will refer to the standard 20-year horizon.

# Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

As addressed in public input meetings and stakeholder feedback forms, the subject of modeling for portfolio evaluation is highly technical. PacifiCorp consults regularly with the provider of the PLEXOS optimization modeling software as these methods are developed. Interested parties are encouraged to review publicly available materials (including recordings) from the 2025 IRP public input meeting series for additional context and information.[2]

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 9 (Modeling and Portfolio Selection Results).

## Key Changes Since the 2023 IRP

The 2025 IRP public meeting inputs series encompassed many key advancements in modeling and evaluation strategy, many driven by stakeholder input. These changes are described in detail later in this chapter. These enhancements are in addition to standard updates applicable to core data such as load and price forecasting. Each change has been incorporated into the company's engagement strategy via public input meetings and stakeholder feedback.[3]

In the 2025 IRP:

- Portfolios must achieve regional and system WRAP compliance.
- Existing thermal units can operate indefinitely with ongoing maintenance.
- IRA Tax Credits are extended through the model horizon (21 years).[4]
- Jurisdictional portfolios are used to integrate final portfolios.
    - States are only able to impact the disposition of resources in which they have an active share.
    - Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction.
- Improved granularity and reliability evaluation.
- No federal $CO_2$ policy adder is assumed in the expected case.
- Transmission representation now includes a distinct bubble for the Wasatch Front.

[2] For discussion of public materials and feedback, see also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[3] See also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[4] The value of production tax credits (PTCs) is reduced in the last five years of the study horizon, to better represent the value of resource additions in the latter half of the horizon. See Appendix M, stakeholder feedback form #63 (Utah Clean Energy) for additional discussion.

- A new price-policy variation ("MR", medium gas price with at-risk federal regulation) has been added to account for changing expectations for future federal policy.
- No market purchases are allowed in peak hours on the five days with the highest peak load in each month, market purchases are allowed up to transmission limits in all other hours.
- The stochastic analysis incorporates wide-ranging historical volatility in renewable shapes, thermal outages, load, market prices, and hydro availability.

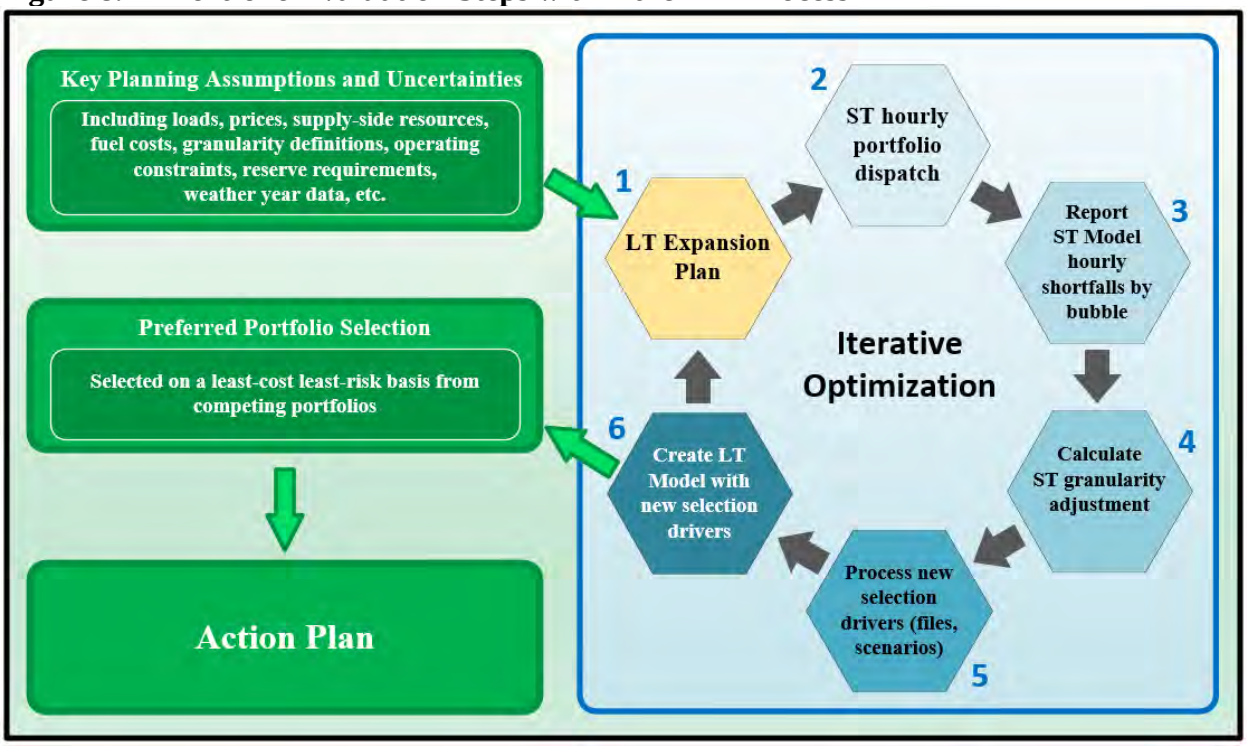
## Modeling and Evaluation Steps

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure 8.1 summarizes the modeling and evaluation steps for the 2025 IRP. The process flow begins at left with the development of key inputs and assumptions. Next, studies are mathematically optimized using PLEXOS software tools[5], as illustrated in the six steps at right ("Iterative Optimization", highlighted in blue). Results are evaluated to determine the least-cost least-risk preferred portfolio from among all eligible portfolios. Finally, the preferred portfolio is used to develop the action plan.[6]

[5] PLEXOS technical modeling assumptions and parameters were discussed in the 2025 IRP public input meeting series and in stakeholder feedback.
See Appendix M, stakeholder feedback form #21 (Renewable Northwest).
See Appendix M, stakeholder feedback form #42 (First Principals Advisory).

[6] The topic of portfolio change was discussed extensively in the 2025 IRP public input meeting series. The modeling and evaluation steps explain how updated inputs are processed – such as updated resource costs as presented in Chapter 7 – resulting in new portfolio outcomes.
See Appendix M, stakeholder feedback form #13 (Joan Entwistle).
See Appendix M, stakeholder feedback form #15 (Sierra Club).
See Appendix M, stakeholder feedback form #27 (Vote Solar).

**Figure 8.1 – Portfolio Evaluation Steps within the IRP Process**




The portfolio development process in the 2025 IRP is an iterative process, whereby PacifiCorp completes initial LT capacity expansion modeling runs for each portfolio. Portfolios are evaluated for cost, reliability and compliance using the ST model, dispatch focused, modeling results. Data regarding resource value and unserved energy quantities from the ST model is fed back into PLEXOS, and the next phase of iterative portfolio optimization is launched. Each cycle through the six steps is one modeling "phase." Iterations continue until the LT capacity expansion model has produced a portfolio that demonstrates no unserved energy in the ST dispatch model run, and then for several phases thereafter, to identify a range of potentially economic candidate portfolios. Each price-policy scenario and each candidate variant study follows this iterative optimization process. Once a completed portfolio phase achieves reliability, as measured using ST model results, evaluation is completed, and results can be compared to other portfolios.

## Overview of Steps in an Iterative Phase

**Step 1**

For each case, the LT capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a "portfolio."

**Step 2**

The LT model expansion plan is fed into the ST model. The ST model performs an hourly dispatch of the portfolio.

**Step 3**

The ST model reports shortfalls as megawatts of unserved energy. These megawatts must be covered for each location (or "bubble") in the IRP transmission topology. Greater detail regarding use of these reported shortfalls to create the reliability adjustment is below.

**Step 4**

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity. Greater detail regarding the calculations which comprise the granularity adjustment is below.

**Step 5**

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

**Step 6**

The next phase LT model is built in PLEXOS, if necessary, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adjustment (either an increase or decrease in costs) to every resource option.

## Granularity Adjustment Detail

The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 4 blocks of hours per month over the 21-year horizon. This means the LT model groups similar hours into a block, calculates the average load and resource parameters specific to each block, and then concurrently solves the entire 21-year horizon. In contrast, the ST model concurrently solves (or dispatches) of a given week, or roughly 52 steps per year of 168 hours each, for a specified portfolio of resources as selected in the LT model. When PLEXOS optimizes the system in the 4-block LT view, it calculates a locational marginal price (LMP) specific to each block of hours. The value of a resource in the LT is equal to its generation in each block, multiplied by the LMP during that block specific to its location, and this value is part of the reported results based on the 48 blocks the LT evaluates during each year (4 blocks per month times 12 months). When the ST model dispatches the same resources at an hourly granularity, it calculates the LMP based on hourly conditions, multiplies by a resource's hourly generation, and reports the resulting value for each resource on an annual basis. The ST model also assigns specific resources to hold operating reserves necessary to meet reliability requirements, calculates the marginal price of reserves, and includes this as part of the reported resource value. The mathematical difference between the ST value and the LT value is the granularity adjustment.

The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between key resource types, they can't capture the full range of hourly conditions.

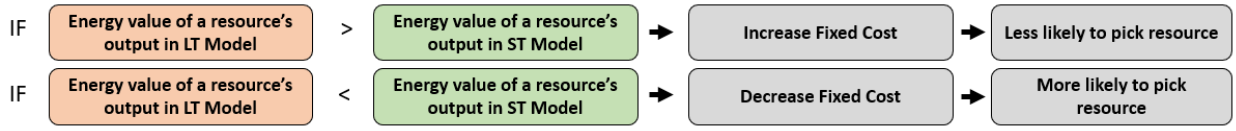
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy

scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 8.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

**Figure 8.2 – Granularity Adjustment Determination**




This iterative process was conducted for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

## Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2025 IRP, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with hourly granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments, these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

In order to avoid diluting singular hourly shortfalls across the entirety of a block, the highest monthly shortfall figure is taken, divided by 4 and applied to each hour in the top ten percent of highest net load hour blocks. The highest shortfall in a month is divided by 4 to avoid overshooting the total amount of resources needed. As an example, suppose the phase zero portfolio (the very first iteration of the six steps for a particular study) reports a maximum shortfall of 400 megawatts in Wasatch Front on June 8, 2032, at 8 PM. The 400-megawatt shortfall is divided by 4 to create a 100-megawatt adder to Wasatch Front load. This 100-megawatt adder is added to the base load file for all of the top ten percent net load hours in Wasatch Front in June of 2032, and phase 1 is run with the adjusted load file. If the portfolio selected in phase 1 reports a maximum shortfall of 100 megawatts in Wasatch Front in 2032, the same process is undertaken and 25 megawatts is added to all ten percent top net load hours, such that the load for that block is now 125 megawatts higher than the original phase zero load forecast. Once no shortfalls are reported by the ST model

(a deterministic run using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These reliability and granularity adjustments result in an iterative loop from the LT model to the ST model and back to the LT model, with results that evolve over multiple phases. This process leads to a portfolio that is reliable on a deterministic hourly basis. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios no longer results in additional cost reductions.

Cost and Risk Analysis

Sufficiently reliable resource portfolios developed by the LT model are simulated through stochastics to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. New to the 2025 IRP, stochastic risk modeling of resource portfolios is performed using actual historical conditions as a guide to volatility and stochastic relationships. These conditions, including weather patterns, thermal outages, fuel and market prices, hydro generation, and wind and solar generation profiles, are mapped to historical dates underlying PacifiCorp's chaotic normal load forecast. PacifiCorp has 18 distinct years of historical data and ran each portfolio using each specific historical year for all years of the 21-year horizon.

The reported stochastic results are based on fifty randomized combinations of the forecasted results based on each historical year. In each of the fifty draws, one historical data year is drawn for each of the years of the IRP study horizon (2025-2045). For example, one draw could include 2025 results based on 2006 weather conditions, 2026 results based on 2015 weather conditions, and 2027 results based on 2020 weather conditions. The same randomized historical year draws are used for all portfolios so that all portfolios can be examined on a comparable stochastic basis. Probabilistic analysis therefore depends upon draws from actual historical variance, which is both more volatile and realistic than prior parameterized variance, improving the verisimilitude of outcomes. The results from these runs are used to calculate a risk adjustment which is combined with ST model system costs to achieve a risk-adjusted PVRR to guide portfolio selection.

Responsive to stakeholder feedback, and like consideration made in past IRPs, cases eligible to become the preferred portfolio which report the possibility of significant end-effects are further evaluated to determine if a portfolio represents significant long-term costs or risks compared to other eligible portfolios.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability, resource adequacy, and $CO_2$ emissions data as an indicator of risks associated with greenhouse gas emissions.

# Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment step as described above. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, $CO_2$ prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

## Long-Term (LT) Capacity Expansion Model

In the 2025 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, zero $CO_2$), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[7] for each load area represented in the model.

The resource portfolios developed using the iterative approach outlined at the beginning of this chapter are appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2025 IRP is based on compliance with the Western Resource Adequacy Program (WRAP) at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2025 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both before and after existing generation resources retire, as well as the years in which to retire existing resources.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025

[7] The PLEXOS model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

IRP, each month was split into four blocks of hours based on load, wind, and solar, based on wind and solar generation profiles based on weather conditions during the specific days used to develop PacifiCorp's chaotic normal load forecast:

1. The top ten percent highest net load hours. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

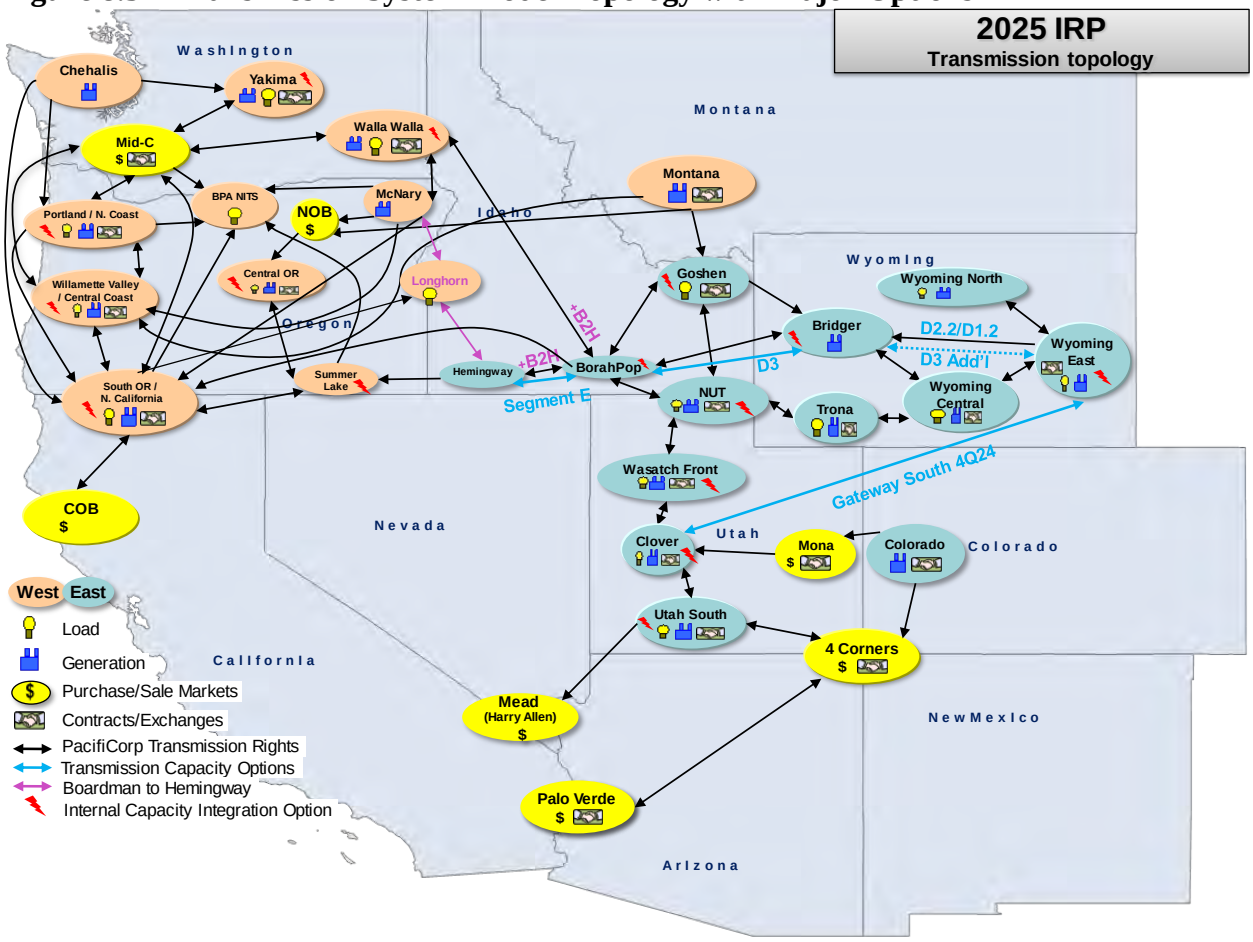
Key modeling elements and inputs for the LT capacity expansion model include the following:

**Transmission System**

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths.[8] Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

[8] Continued interest was expressed on stakeholder feedback regarding the assumption of a Wyoming market hub to represent the opportunity afforded by certain transmission constraints. In light of the restrictions on the types of market products that can count toward WRAP capacity requirements, PacifiCorp's modeling does not count any short-term market products toward WRAP compliance and has limited market purchases at all points during the highest load conditions in each month, to represent potential market liquidity limits. See Appendix M, stakeholder feedback form #39 (Western Resource Advocates).

**Figure 8.3 – Transmission System Model Topology with Major Options**




This map is for general reference only regarding IRP topology.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Figure 8.3 illustrates the 2025 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

## Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meetings, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.[9,10]

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be

[9] Wildfire mitigation in the context of transmission was discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).
[10] Transmission modeling, cluster studies and details of resource-to-transmission relationships were discussed extensively during the 2025 IRP public input meeting series and in stakeholder feedback. See Appendix M, stakeholder feedback form #40 (Renewable Northwest).

impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.
- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Cluster Study 3:** Spring 2023 requests
- **Colstrip:** Interconnection to jointly owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. For the 2025 IRP, PacifiCorp has transitioned to using cluster studies to indicate the earliest year a resource type is eligible for selection in any given location (as well as using recent cluster study data as compiled by PacifiCorp Transmission to indicate potential transmission upgrades and costs). Cluster studies are described further in Chapter 4.

Surplus Interconnections

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time at that location cannot exceed the original interconnection capacity.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

**Transmission Costs**

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

**Resource Adequacy**

In its 2025 IRP, PacifiCorp included the monthly planning reserve margin requirements from the Western Resource Adequacy Program (WRAP) in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. While WRAP is expected to enhance reliability, the monthly capacity contribution values assigned to each resource may not be sufficient to meet hourly requirements in every location, so it does not eliminate the need for reliability assessment. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

**Granularity and Reliability Adjustments**

As detailed during the 2025 IRP public-input process, the granularity adjustment reflects the difference in economic value in resource options and transmission between an hourly 8760 cost calculation in ST modeling, and the monthly blocking representation used in the LT model.[11]

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, in a single pass, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger

[11] See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon) for responses to questions regarding modeling transmission and granularity adjustments. The method for evaluating granularity value for transmission is the same as for supply-side resources, in that the model reports values used for the granularity adjustments based on the resource's contribution to reducing cost and risk.
See also Appendix M, stakeholder feedback form #36 (Sierra Club).

share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

**Thermal Resource Options**

Continuing best practice from the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection in the 2025 IRP. Other renewable technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when, or whether, they should retire.

Table 8.1 and Table 8.2 report the coal unit options modeled in the 2025 IRP, whereas Table 8.3 summarizes the options available for natural gas-fired units.

**Table 8.1 – Majority-Owned Coal Generator Resource Options[12,13]**

| Jim Bridger Units 3 and 4 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire-2030/2039 111(d) | | | | | | Dual Fuel | - | - | - | - | - | - | - | - | Gas | - | - | - | - | - | - |
| Coal-CCS 2030 | | | | | | CCS+45Q | | | | | | | | | | | | CCS | - | - | - |
| **Dave Johnston 1 and 2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028-2029/Gas Conv. 2029 | | | | - | Gas | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Dave Johnston 3** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028 | | | | Retired | | | | | | | | | | | | | | | | | |
| **Dave Johnston 4** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire-2030/2039 111(d) | | | | | | Dual Fuel | - | - | - | - | - | - | - | - | Gas | - | - | - | - | - | - |
| Coal CCS+SCR 2032 | | | | | | | | CCS+45Q | | | | | | | | | | | | CCS | - |
| **Wyodak** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028 thru 2045 | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire-2030/2039 111(d) | | | | | | Dual Fuel | - | - | - | - | - | - | - | - | Gas | - | - | - | - | - | - |
| Coal CCS+SCR 2032 | | | | | | | | CCS+45Q | | | | | | | | | | | | CCS | - |
| **Hunter 1-3** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire Alt. Fuel-2030/2039 111(d) | | | | | | Dual Fuel | - | - | - | - | - | - | - | - | Alt. Fuel | - | - | - | - | - | - |
| Coal CCS+SCR 2032 | | | | | | | | CCS+45Q | | | | | | | | | | | | CCS | - |
| **Huntington 1-2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Coal 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire Alt. Fuel-2030/2039 111(d) | | | | | | Dual Fuel | - | - | - | - | - | - | - | - | Alt. Fuel | - | - | - | - | - | - |
| Coal CCS+SCR 2032 | | | | | | | | CCS+45Q | | | | | | | | | | | | CCS | - |

Key

| | | | |
|---|---|---|---|
| | Default/current operation | 45Q | CCS |
| | Retirement Option | | Alternative Fuel |
| | Gas conversion option | | Assumed retired |

[12] While 111(d) compliance can be met with dual fuel operations in 2030-2038, due to engineering uncertainty and modeling complexity, starting in 2030 100% of the fuel input for these options comes from natural gas or alternative fuel. For Hunter and Huntington, which are not located in proximity to natural gas pipeline transport, the alternative fuel modeled in the 2025 IRP is based on the cost of biodiesel, which results in a dispatch price of over $400/MWh (2024$).

[13] After the filing of the 2023 IRP Update on March 31, 2024, a change occurred in the timing of implementation of carbon capture on Jim Bridger Units 3 and 4. CCS assumption for these units is updated for the 2025 IRP. See Appendix M, stakeholder feedback form #5 (Powder River Basin).

**Table 8.2 - Minority-Owned Coal Generator Resource Options**

| Minority-Owned Units | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Colstrip 3 | | PAC share moves to Unit 4 | | | | | | | | | | | | | | | | | | | |
| Colstrip 4 | *Includes Unit 3 share* | | | | | | | | | | | | | | | | | | | | |
| Craig 1 | | | | | | | | | | | | | | | | | | | | | |
| Craig 2 | | | | | | | | | | | | | | | | | | | | | |
| Hayden 1 | | | | | | | | | | | | | | | | | | | | | |
| Hayden 2 | | | | | | | | | | | | | | | | | | | | | |

Key: Default/current operation; Assumed retired

**Table 8.3 - Natural Gas Generator Resource Options[14]**

| Chehalis | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas-2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cofire/non-emitting 2030 | | | | | | | | | | | | | | | | | | | | | |
| **Currant Creek** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Hermiston 1/2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2028 thru 2039/Alt. Fuel | | | | - | - | - | - | - | - | - | - | - | - | - | - | | | | | | |
| **Jim Bridger Units 1 and 2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Lakeside 1** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Lakeside 2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Naughton Units 1 and 2** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2026 thru 2045 | | Gas | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Naughton Unit 3** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas-2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Gadsby Steam 1-3** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Gadsby CTs 4-6** | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| Gas 2028 thru 2045 | - | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Key: Default/current operation; Retirement option; Assumed retired; Alternative Fuel; Current (Coal)

## New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

[14] PacifiCorp has insufficient detail at this time to evaluate alternative fueling options at its Chehalis and Hermiston natural gas-fired facilities, particularly in light of possible impacts on cost-allocation and market participation and has adopted Action Plan item 1h to advance options for potential implementation by 2030.

Wind and Solar Resources

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources are based on the weather conditions from the same historical days used to develop the load forecast.

The ability for wind and solar resources to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio.

Non-Emitting Resources

Four non-$CO_2$-emitting thermal resources are considered: nuclear projects, small renewable fuel peaking resources, geothermal resources, and non-emitting hydrogen peaking units leveraging on-site electrolysis with 24 hours of tank storage. Nuclear resources and geothermal are characterized by continuous operation, with the Natrium project combining this operation with storage in the form of heat stored as molten salt. In contrast, peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The small renewable peaking resource for the 2025 IRP is assumed to use biodiesel or renewable diesel, both of which are commercially available. While combustion of these fuels releases $CO_2$ it is not derived from fossil sources and is eligible to meet compliance requirements in both Oregon and Washington.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period.
- Energy return – energy used to fill (or charge) a storage reservoir.
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or

the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process.

**Capital Costs**

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes, income taxes, and demolition costs over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

**General Assumptions**

Study Period and Date Conventions

PacifiCorp executes its 2025 IRP models for a 21-year period beginning January 1, 2025, and ending December 31, 2045. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

Inflation Rates

The 2025 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.18 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2025 through 2045, using PacifiCorp's September 2024 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2025 IRP is 6.38 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[15] PVRR figures reported in the 2025 IRP are reported in 2024 dollars.

[15] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

## $CO_2$ Price Scenarios

PacifiCorp used three different $CO_2$ price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse gas scenario is derived from forecasts of greenhouse gas costs in Washington and California but is applied like a federal obligation throughout the system starting in 2030. Impacts in the scenario which includes current federal regulations also become relevant in 2030, as coal-fired resources must select between retirement, carbon capture, or co-firing by this time.

The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.[16] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

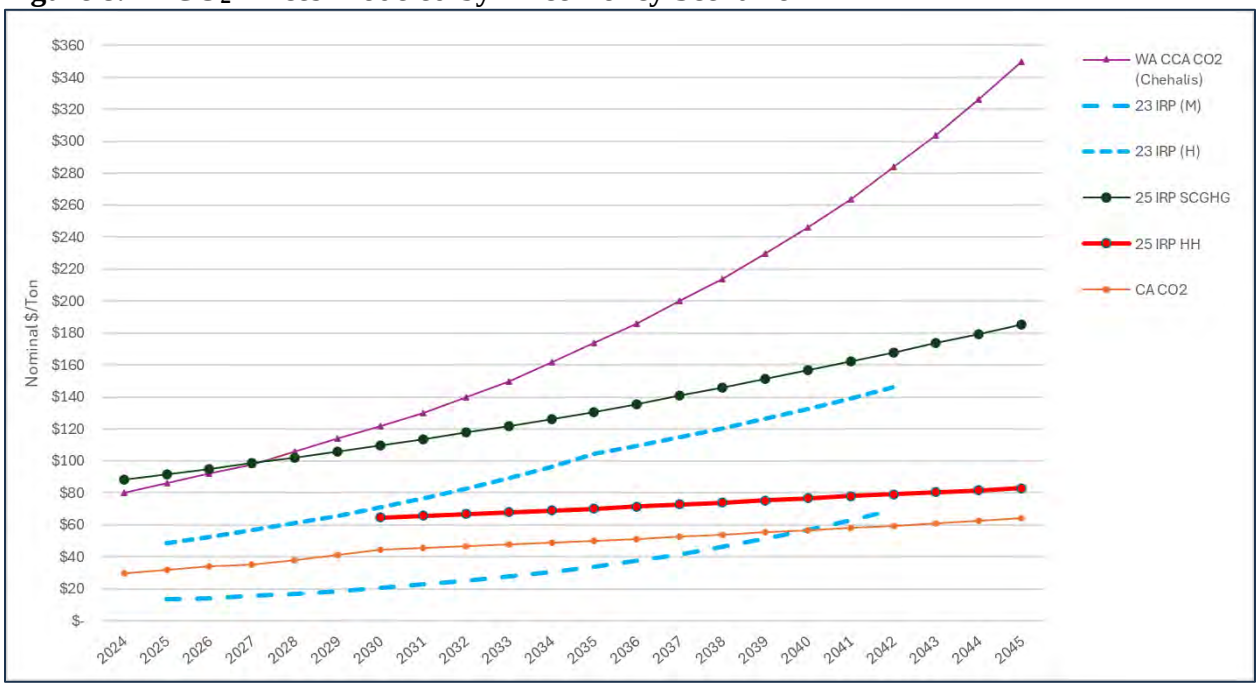
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[17] This is in addition to the assumed federal $CO_2$ policy represented in the zero, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost is based on the allowance cost cap identified by the Washington Department of Ecology and starts at $88 metric ton in 2024.[18]

[16] Washington Utilities and Transportation Commission, Order 05, Docket No. U-190730, July 25, 2024. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=27&year=2019&docketNumber=190730 (Accessed 11/8/2024).

[17] Stakeholder feedback requested modeling Chehalis without consideration of Washington's Climate Commitment Act. Notwithstanding that certain commissions have declined to allow the company to recover these costs, the company continues to incur these costs, which are therefore modeled. See Appendix M, stakeholder feedback form #19 (Wyoming Office of Consumer Advocate).

[18] Washington Cap-and-Invest Program 2024 Annual Allowance Price Containment Reserve Tier Price and Price Ceiling Unit Price Notice. December 2023. Available online at: https://apps.ecology.wa.gov/publications/documents/2302066.pdf (Accessed 11/8/2024).

**Figure 8.4 – $CO_2$ Prices Modeled by Price-Policy Scenario**




Wholesale Electricity and Natural Gas Forward Prices

For 2025 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2025 IRP modeling inputs were prepared, the September 2024 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[19] As such, these 36 months are market forwards as of September 2024. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[20] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios using high or low gas prices do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also

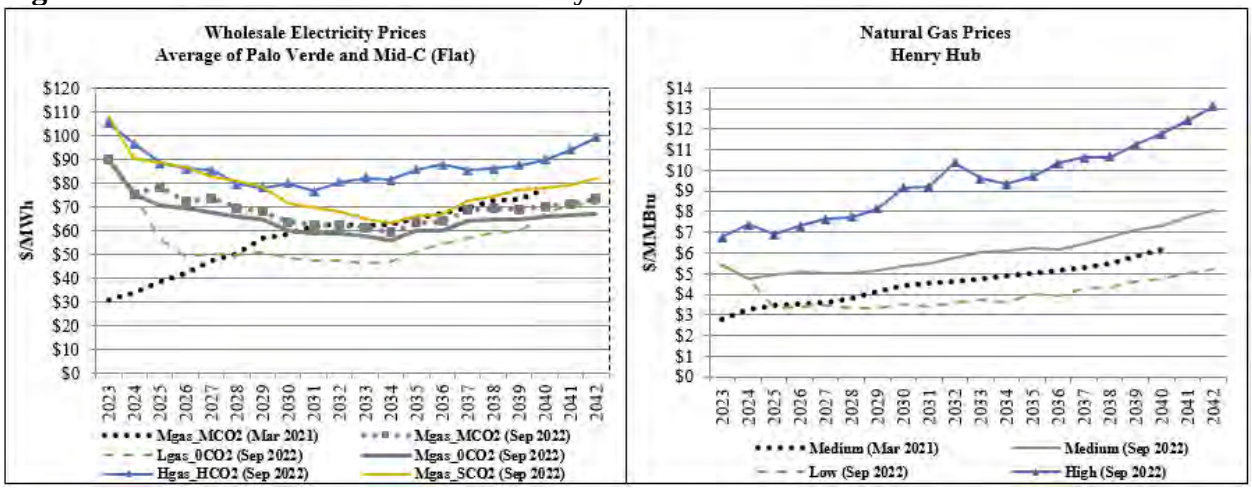
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

derived from an expert third-party forecast. Similarly, the SCGHG scenario does not incorporate any market forwards since that greenhouse gas policy represents an alternative view that applies throughout the study period.

New to the 2025 IRP, in response to stakeholder feedback and requests related to volatility in coal pricing, the high gas and market price-policy scenario also includes an elevated coal fuel supply cost. This represents risks such as supply-chain issues as well as the potential for increased transportation costs or other increased variable coal costs which are not present in the base forecast for coal pricing.[21] The increased cost calculated for coal pricing was developed by evaluating the percentage difference in the average annual gas prices at Henry Hub between the medium and high cases. Annual percentage differences were then applied to each coal plant's coal supply price over the 21-year horizon.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP.

**Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios**




## Cost and Risk Analysis

### Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model coupled with the portfolio selected by the LT model. LT results provide the initial capacity expansion plan for the ST model to dispatch.

[21] Coal supply, costs and risks were discussed in the 2025 IRP public input meeting series and stakeholder feedback. In the 2025 IRP, PacifiCorp considers base coal cost assumptions, the Jim Bridger Long-term Fuel Plan sensitivity, and coal-related variant studies. For stakeholder feedback and responses:
See Appendix M, stakeholder feedback form #28 (Utah Citizens Advocating Renewable Energy).
See Appendix M, stakeholder feedback form #29 (Utah Clean Energy).
See Appendix M, stakeholder feedback form #30 (Katie Pappas).
See Appendix M, stakeholder feedback form #31 (Jane Myers).
See Appendix M, stakeholder feedback form #32 (Sara Kenney).

**Reliability Assessment and System Cost**

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario.

As discussed at the start of the chapter, these data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

Resource Value

PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. PLEXOS also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, utility scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. New for the 2025 IRP, small resources (those with a capacity of fewer than 20 megawatts) are eligible to be sited within any of the load regions and unconstrained by new transmission requirements, as PacifiCorp's studies have shown resources that are sufficiently small and sized consistent with the local grid can be feasible without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply-side resource table). In initial jurisdictional runs, small generator and local battery resources are limited based on the load in each transmission bubble, due to the assumption these are sized to serve local load so as not to require transmission investment.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. Within a transmission constraint, batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

Each run of the ST model produces an optimized dispatch of a portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT model. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual energy not served (ENS)
- Annual $CO_2$ emissions.

## Stochastic Modeling

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. For the 2025 IRP, stochastic risk modeling of resource portfolio alternatives is performed with the ST model.

The standard ST model inputs reflect a normalized view of future conditions and the typical range of outcomes across each month. For stochastic modeling in the 2025 IRP, alternative inputs are used that reflect conditions analogous to actual results in a specific historical year. Stochastic

inputs for the 2025 IRP have been expanded and now include wind and solar generation profiles, along with the energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

**Stochastic Conditions**

For the 2025 IRP, PacifiCorp has data reflecting eighteen discrete annual conditions, specifically the historical data and variances from 2006-2023 for each of the stochastic inputs. By running eighteen ST model scenarios covering each of these conditions, results can encompass the full range of conditions. However, each of these ST model scenarios represents conditions from a single year repeating in every year of the study horizon, with slight differences from year to year to account for days of the week, plus load growth, climate change impacts on load and hydro, and changes in the resource portfolio. For instance, using historical data based on 2015, every year from 2025-2045 would be a dry hydro year (below average). There are benefits to compiling the results in this way, as it will be easier to identify specific historical weather conditions that are leading to high costs and ENS. But to produce portfolio performance measures, random sampling of the annual results may be appropriate, particularly for assessment of multi-year compliance requirements such as renewable portfolio standards (RPS) and Washington's Clean Energy Transformation Act (CETA).

**Stochastic Portfolio Performance Measures**

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the Monte Carlo annual draws include:

- Stochastic mean PVRR
- $5^{th}$, $90^{th}$ and $95^{th}$ percentile PVRR
- Standard deviation
- Risk-adjustment
- Energy Not Served (ENS)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long-term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include $CO_2$ emission costs for any scenarios that include a $CO_2$ price assumption. The stochastic mean PVRR, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.
.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 18 results drawn from the ST runs under 18 distinct stochastic conditions. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 random draws of the 18 runs under stochastic conditions. The production cost is expressed as a net present value of annual costs over the IRP horizon. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The model outcomes of the 50 random draws are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 random draws for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Energy Not Served (ENS)

In past IRPs, the use of the reduced granularity in the PLEXOS MT model limited the relevance of the reported ENS. In the 2025 IRP, the ST model's full 8760 granularity is being reflected in stochastic analysis, so reported ENS is representative of a portfolio's performance in the real-world historical conditions that underlie the stochastic inputs.

**Forward Price Curve Scenarios**

Preferred portfolio variants developed during the portfolio-development process are analyzed under up to five price-policy scenarios.

**Other PLEXOS Modeling Methods and Assumptions**

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the PLEXOS models. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in normalized and stochastic ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. For the 2025 IRP, PRM and resource contributions based on WRAP are used as part of portfolio selection, but this is not part of resource dispatch. In addition to WRAP compliance, ST reliability modifications to the portfolio evaluate hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level.

Energy Storage Resources

Storage resources have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each PLEXOS model dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

## Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and $CO_2$ emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

**Fuel Source Diversity**
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

**Customer Rate Impacts**
To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

**Market Reliance**
To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 (Modeling and Portfolio Selection Results). Starting in the

2021 IRP, market purchases were restricted compared to past IRPs, as described in Chapter 7 (Resource Options).

## Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS, $CO_2$ emissions, and compliance with state and federal policies. The risk-adjusted PVRR accounts for relative risk of volatility among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include stochastic PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

## Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the PLEXOS models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and $CO_2$ emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

## Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2025 IRP, organized here into major development categories:

- Initial Portfolios, including all variants
    - Initial portfolios and variants are evaluated under three distinct sets of jurisdictional requirements:
        - Utah/Idaho/Wyoming/California.
        - Oregon.
        - Washington.

    - Integrated Portfolios incorporate selections from the top performing initial portfolios under each set of jurisdictional requirements.
    - The preferred portfolio is selected based on the integrated portfolio results.
- Jurisdictional Analysis
- Sensitivity Cases

Additional portfolio detail can be found in Appendix I (Capacity Expansion Results).

## Initial Portfolios

Informed by the public-input process, the initial cases explore significant interactions among retirement options including the potential to convert coal units to natural gas or biodiesel operations, install carbon-capture equipment on coal-fired facilities, and retire units during the study horizon. The modeling continues to include a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and zero $CO_2$ price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of the optimization models within PLEXOS.

## Jurisdictional Definitions and Modeling

As discussed above, distinct requirements exist for various jurisdictions, and some of these requires conflict. As a result, initial portfolio modeling is used to separate the requirements as described below, allowing for the development of optimal portfolios of resources to meet jurisdictional needs.

Compared to Oregon and Washington, modeling for Utah/Idaho/Wyoming/California (UIWC) is more focused on least-cost resource selection regardless of fuel type. UIWC resources must meet the Western Resource Adequacy Program (WRAP) requirements for this jurisdiction. As a result, the only modeling constraint for this jurisdiction is one which combines load and requires the model to select enough total resources (including existing resources under current allocation protocols) to meet WRAP planning requirements. All resources are eligible for inclusion in these states and this requirement.

All Washington resource selections are analyzed and optimized assuming the SCGHG price-policy scenario, as required under RCW 19.280.030 for clean energy planning.

Oregon initial portfolios model compliance with House Bill 2021. Oregon participates in existing coal-fired resources through 2029 and existing gas-fired resources (including the gas conversions of Naughton 1 and 2 in 2026 and the endogenously selected conversion of Dave Johnston Units 3 and 4 in 2029) through 2039. Emissions allocated to Oregon from existing resources are calculated based on Oregon's current share of the resources and the appropriate Oregon DEQ emissions factors. Like other jurisdictions, Oregon must be WRAP compliant. PLEXOS models face challenges meeting annual emissions constraints due to the need to model slices of time in each different model (as described earlier in this chapter). This has been addressed by assessing a

shadow price on Oregon allocated emissions as a model driver to ensure HB 2021 compliance is achieved. The shadow price is not reported from the model as a cost to customers, but is instead used to impose a penalty on the model if Oregon allocated resources emit $CO_2$-E. This price drives the model to reduce emissions (and generation) and select additional resources to meet Oregon load. Compliance for Oregon is measured by determining whether there is enough Oregon-allocated generation to meet Oregon load on an annual basis while also having emissions below the Oregon required thresholds.

Five price-policy scenarios were evaluated in this IRP:

- MN: Medium natural gas/No federal $CO_2$regulations
- MR: Medium natural gas/current federal $CO_2$ regulations under Section 111 of the Clean Air Act.
- LN: Low natural gas/No federal $CO_2$ regulations.
- HH: High natural gas/High $CO_2$ cost applied to all generators (updated $CO_2$ forecast, starting 2030) with no other federal $CO_2$ regulations.
- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal $CO_2$ regulations.

Table 8.4 provides the price-policy case definitions for the 2025 IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Appendix I (Capacity Expansion Results).

**Table** 8.4 – Price-Policy Case Definitions

| Price-Policy | Existing Coal[(b)] | Existing Gas[(b)] | Other Existing Resources | Proxy Resources[(c)] |
|---|---|---|---|---|
| MN | Optimized | Optimized | End of Life | All allowed |
| MR | Optimized | Optimized | End of Life | All allowed |
| LN | Optimized | Optimized | End of Life | All allowed |
| HH | Optimized | Optimized | End of Life | All allowed |
| SC | Optimized | Optimized | End of Life | All allowed |

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(b) Optimized proxy portfolio selections include renewables, offshore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

In all five price-policy scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This cost is incremental to the $CO_2$ cost included in each price-policy scenario. Where applicable, the price-policy scenarios above represent $CO_2$ as a cost applicable to all emitting resources, based on the direct emissions associated with the fuel consumed by each generator.

The 2023 IRP included a medium natural gas/medium $CO_2$ (MM) price-policy scenario. The MM price-policy scenario, which was the price-policy included in the 2023 IRP preferred portfolio, was excluded from the 2025 IRP. In the 2023 IRP, the MM price-policy was included as a proxy to represent potential future federal $CO_2$ regulations. For the 2025 IRP the MR price-policy scenario, which was not included in the 2023 IRP, encompasses federal $CO_2$ regulations. This

price-policy scenario was added in response to the final $CO_2$ regulations issued by EPA on April 25, 2024, which apply to new natural gas-fired combustion turbines and existing coal, oil, and gas-fired steam turbines.

All portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

Certain additional cases were developed based on stakeholder feedback and state requirements to evaluate the impacts of specific future scenarios. These cases are all eligible to be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2025 IRP, there are the following variant portfolio selection cases as shown in Table 8.5.

**Table 8.5 – Portfolio Variants**

| Variant | Description | Refer to Case |
|---|---|---|
| **No CCS** | No coal units are able to select CCS technology | - |
| **No Nuclear** | No nuclear resources are eligible for selection | - |
| **No Coal 2032** | All coal must retire or convert to gas by January 1, 2032 | - |
| **Offshore Wind** | Counterfactual to the Preferred Portfolio selection: Offshore wind must be selected | - |
| **No Forward Technology** | No nuclear, hydrogen storage, 100-hour storage or biodiesel peaking | - |
| **Geothermal** | Counterfactual to the Preferred Portfolio selection: Geothermal must be selected | - |
| **Hunter Retire** | Require all Hunter units to retire no later than 1/1/2030 | - |
| **All Coal End of Life** | Continue 2025 coal technology | See the No CCS variant |
| **No New Gas** | No new gas resources allowed | See the Preferred Portfolio |
| **Force All Gas Conversions** | Force all coal-to-gas options | See the No Coal 2032 variant |

Each variant case begins with the same PLEXOS dataset inputs and assumptions, and adds the constraints to either force a selection, disallow a specific resource or resource type, delay a project or force retirements as outlined below.

### No CCS

This variant removes the CCS option at Jim Bridger 3 and 4. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were not a commercially viable

option. This variant was analyzed twice, once using the MN price-policy scenario and once using the MR price-policy scenario.

**No Nuclear**

This variant removes the Natrium™ demonstration project in 2030 and all other nuclear resources from available resource options. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of the variant is to evaluate resource alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk if nuclear resources are unable to achieve online and operating status for any reason.

**No Coal 2032**

In this variant all coal plants are assumed to retire no later than 2032. Coal plants are eligible to run past 2032 if gas conversion is selected at that plant. No CCS options are available in this variant. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if external factors required coal plants to cease coal-fired operations by 2032.

**Offshore Wind**

Offshore wind was available for selection in all portfolios beginning in 2033, based on the timing of necessary transmission upgrades. As offshore wind has not been endogenously selected in the preferred portfolio, a minimum of 1000 MW was required to be selected in this variant. Additionally, the necessary onshore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. This counterfactual is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

**No Forward Technology**

In this variant all nuclear, hydrogen storage, 100-hour battery, and biodiesel peaking resources are removed from the preferred portfolio and the portfolio is re-optimized without these resource options. The removal of 100-hour battery as an option in this variant is in response to stakeholder request.[22] The purpose of this variant is to evaluate the cost and risk impacts of limited new resource types becoming available in the future.

**Geothermal Counterfactual**

Like the offshore wind case, advanced geothermal units are available for selection in all portfolios in Central Oregon and Southern Utah starting in 2027. These resources require transmission upgrades to be enabled. Pursuant to stakeholder interest[23], as geothermal is not selected for the Preferred Portfolio, a minimum of 707 MW of geothermal resource must be built

[22] See Appendix M, stakeholder feedback form #55 (Utah Division of Public Utilities).
[23] See Appendix M, stakeholder feedback form #56 (Utah Clean Energy).

in Central Oregon or Southern Utah. This counterfactual is used to assess system impacts and the magnitude of costs associated with geothermal and its associated transmission requirements.

**Hunter Retire**

Responsive to stakeholder interest, a variant is considered that forces all three Hunter coal units to cease all operations by 2030.[24] This variant forces the retirement of the Hunter Plant in any year from 2028 to 2030. The purpose of this variant is to assess the impact on cost and emissions when Hunter is precluded from continued operation.

**All Coal End of Life**

> *The No CCS run selects coal at all current coal sites and does not choose to retire any eligible units. Please refer to the No CCS variant for results.*

In this variant all coal plants are assumed to run as coal-fired units using the technology present on the plant as of January 1, 2025, and are not eligible to retire during the study horizon unless otherwise required to do so. Dave Johnston units 1-3 along with Naughton units 1 and 2 still retire or cease coal-fired operation as necessary. Minority owned coal plants are also assumed to retire as necessary for environmental compliance. The purpose of this variant is to evaluate how the preferred portfolio would change if majority-owned coal resources were allowed to run as coal-fired to end-of-life.

**No New Gas**

> *The unconstrained integrated MN case does not select new natural gas resources. Please refer to the Preferred Portfolio for results.*

This variant assumes no new gas resources are allowed to be selected. This does not include the conversion of coal plants from coal-fired to gas-fired. The purpose of this variant is to evaluate the cost and risk impacts of replacing new gas resources selected in the preferred portfolio with other energy resources.

**Force All Gas Conversions**

> *The No Coal 2032 selected all plants eligible for gas conversion. Please refer to the No Coal 2032 variant for results.*

In this variant all coal plants eligible for gas conversion are forced to do so. The gas converted coal plants are allowed to retire endogenously, and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts associated with gas conversion becoming the only future option for all coal-fired plants. Hunter and Huntington, which are not eligible for gas conversion, were eligible for alternative fuel conversion but were not forced to convert.

## Integrated Portfolios

Portfolio integration involves combining resource selections from each of the initial jurisdictional portfolio results under a given price-policy scenario or variant. Every initial jurisdictional portfolio

[24] See Appendix M, stakeholder feedback form #53 (Sierra Club).

evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies, identified as 1) "UIWC" for Utah, Idaho, Wyoming and California, 2) "OR" for Oregon and 3) "WA" for Washington. Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction's initial portfolio result. Given concerns related to the availability of transmission on an hourly basis between the West and East sides of PacifiCorp's system, the selection of proxy resources on the West is determined jointly by the Oregon and Washington initial jurisdictional portfolios, and the selection of proxy resources on the East is determined by the initial jurisdictional UIWC portfolio. Accordingly, only the jurisdictional portfolios that determine the selection of a given resource are eligible to participate in that resource.

**Table 8.6 – Portfolio Integration Resource Example**

| Jurisidiction | Fixed Share | Initial Portfolio Selection (MW) | Total Allocation (MW) |
|---|---|---|---|
| Oregon | 75% | 150 | 112.5 |
| Washington | 25% | 60 | 37.5 |
| Total | 100% | | 150 |

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year. This integration process is applied to every initial portfolio.

The initial integration step has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may be shared with other jurisdictions. Thus, the final step of the integration process is to identify and remedy any such shortfalls in energy and capacity compliance.

## Washington Portfolios

The integrated preferred portfolio reflects Washington customer energy and capacity needs and the CETA clean energy standards from 2030 onwards. The final integrated portfolio presents a CETA-compliant path towards the production of a quantity of clean megawatt hours that meets Washington's retail sales on an annual basis, as described in further detail in Appendix O (Washington's Clean Energy Action Plan). This CETA-compliant portfolio is a starting point for the analysis that will be provided in the forthcoming 2025 Clean Energy Implementation Plan (CEIP), expected to be filed with the Washington Utilities and Transportation Commission in October 2025.

The focus of this IRP filing is to present an integrated preferred portfolio that meets all state-specific requirements. As described in this chapter and further in Appendix Othe IRP preferred portfolio presents a strategy to get to a portfolio that is optimized to meet Washington CETA clean energy standards over the next twenty years. The following scenarios and sensitivities required by Washington rule are also included.

Per WAC 480-100-620(10): the IRP must also include a range of possible future scenarios and input sensitivities. These include:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is comparable to the initial SCGHG price-policy scenario study but includes Washington-specific capacity requirements based on WRAP. This sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding how climate change is incorporated into the base load forecast. Climate change impacts are also incorporated in the base hydro forecast. Because the base forecast includes climate change, all the IRP analysis reflects impacts related to climate change and a separate sensitivity to include these impacts is not necessary.

- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission options and relies on increased small-scale renewables. Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

## Sensitivity Case Definitions

PacifiCorp identified a variety of sensitivities outlined in Table 8.7 and discussed further in Chapter 9.

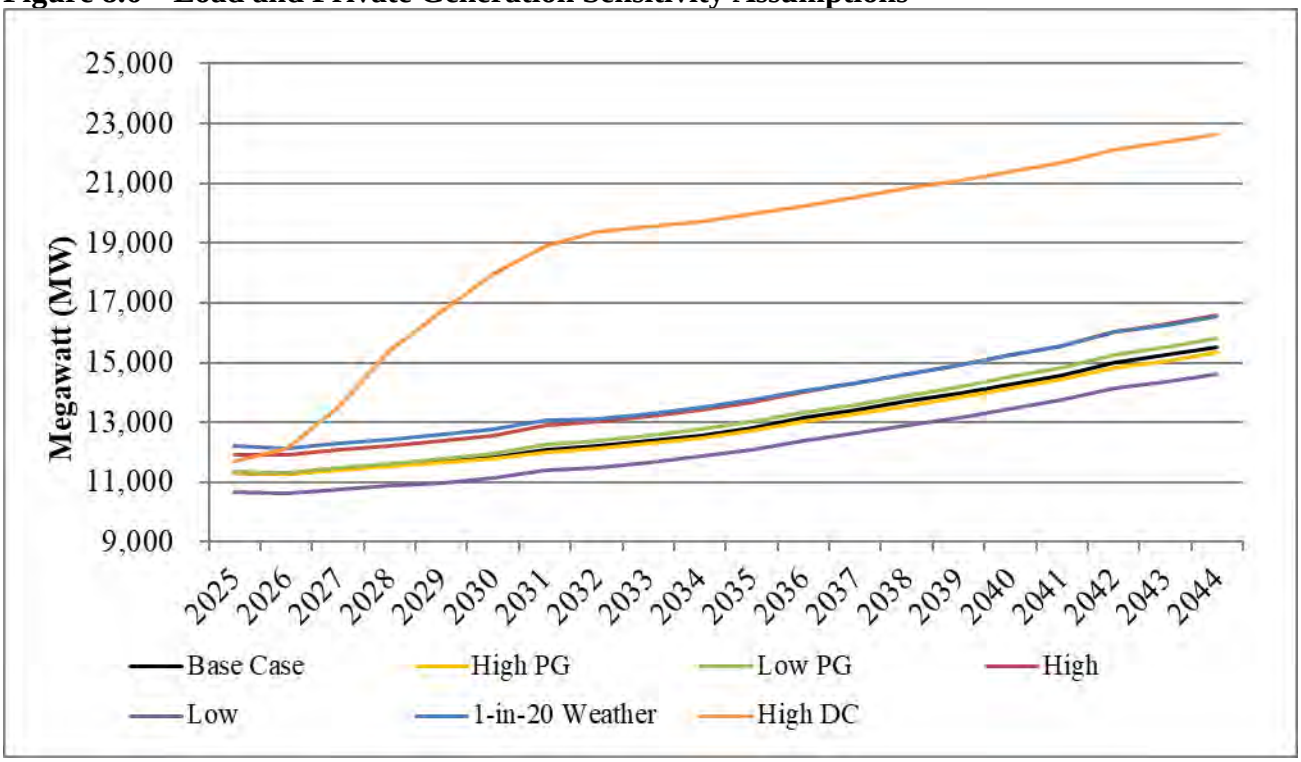
**Table 8.7 – Sensitivity Case Definitions**

| Sensitivity | Definition |
|---|---|
| High Load Growth | Base load forecast replaced by a high load version |
| Low Load Growth | Base load forecast replaced by a low load version |
| 1-20 Peak Load | Base load forecast replaced by a high load version using historical 20-year highest load |
| High Private Generation | Assumes lower load due to high private generation adoption |
| Low Private Generation | Assumes higher load due to low private generation adoption |
| Large Metered Load Growth | Assumes significant large-metered customer load growth |
| Low-Cost Renewables | Assumes high adoption of IRA/IIJA benefits leads to large cost declines |
| Low PTC/ITC eligibility | Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window |
| All CCS | Allows CCS to be selected at additional coal units |
| Business as Usual | Portfolio if no state requirements existed |
| Business Plan | First 3 years are aligned with the current business plan |

## Load Sensitivities

The 2025 IRP includes several sensitivities related to load forecast assumptions. Figure 8.6 provides a comparison of load by year for each case, including the base assumption for comparison. Definitions for all sensitivities are then discussed individually, below.

**Figure 8.6 – Load and Private Generation Sensitivity Assumptions**




## High Load Growth

In this sensitivity the base load forecast is replaced with a high load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher loads.

**Low Load Growth**
In this sensitivity the base load forecast is replaced with a low load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of lower loads.

**1 in 20 Peak Load**
In this sensitivity the base load forecast based on median load conditions (exceedance in 10 of 20 years) is replaced with a higher load forecast based on peaks that reflect an expected 1 in 20 year exceedance level. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher peak loads.

**High Private Generation**
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high private generation adoption which reduces load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with high private generation adoption.

**Low Private Generation**
In this sensitivity the base load forecast is replaced with a new load forecast incorporating low private generation adoption which increases load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with low private generation adoption.

**Large-Metered Load Growth**
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high large-metered load growth. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of this future. A variety of transmission upgrades are necessary to meet the significant load increases contemplated in this sensitivity, including B2H. This portfolio uses the same integration process as the preferred portfolio to address any state compliance shortfalls.

**Low-Cost Renewables**

This sensitivity assumes high IRA/IIJA adoption results in significant cost reductions for PTC/ITC eligible resources, making them more likely to displace non-PTC/ITC eligible resources. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how the availability of lower cost renewables might impact cost and risk.

**Low PTC and ITC Eligibility**

This sensitivity assumes IRA/IIJA changes result in PTC and ITC eligibility ending in 2030. Resources coming online after 2030 do not have the cost reductions associated with PTC and ITC. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how lower than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

**All CCS**

This sensitivity allows CCS to be selected at Wyodak, Hunter Units 1-3, Huntington Units 1 and 2, and Dave Johnston Unit 4, in addition to the option of CCS at Jim Bridger Units 3 and 4. , This sensitivity relies on the assumption that it is feasible to complete installations at all of these units prior to 2032. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were a commercially viable option at more than one coal site before 2032.

**Business As Usual[25] (No Pending Legislation or State Requirements; Locked Coal Assumptions)**

In this sensitivity, all pending legislation and state requirements are removed so that the only obligations to be met are load and federal policy obligations. Coal outcomes are also set so that coal plants retire no earlier than assumed in the 2017 IRP Update except to the extent that updated commitments or requirements supersede the older assumptions. The portfolio is otherwise fully endogenous. The purpose of this variant is to evaluate how the preferred portfolio would change if no potential state requirements or early economic retirements were considered.

**Business Plan Sensitivity**

*The unconstrained integrated MN case does not select new resources in the first three years, please refer to the Preferred Portfolio for results.*

In the 2025 IRP, this case has the same assumptions as the integrated preferred portfolio. For this reason, no additional sensitivity is needed. The case complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the PLEXOS models.

[25] Per the Wyoming Public Service Commission's (WPSC) 2019 Investigation Order (DOCKET NO. 90000-144-XI-19, and DOCKET NO. 90000-147-XI-19), "reference case" is the formal terminology for the business-as-usual study. Regarding this study, the WPSC mandates the following:

> "In the anticipated 2021 IRP, and in IRPs and updates thereto filed by the Company thereafter, Rocky Mountain Power shall:
>
> a) Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and only incorporate environmental investments or costs required by current law"

This case was the subject of stakeholder feedback and discussion in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #35 (Wyoming Energy Authority).

# CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

## CHAPTER HIGHLIGHTS

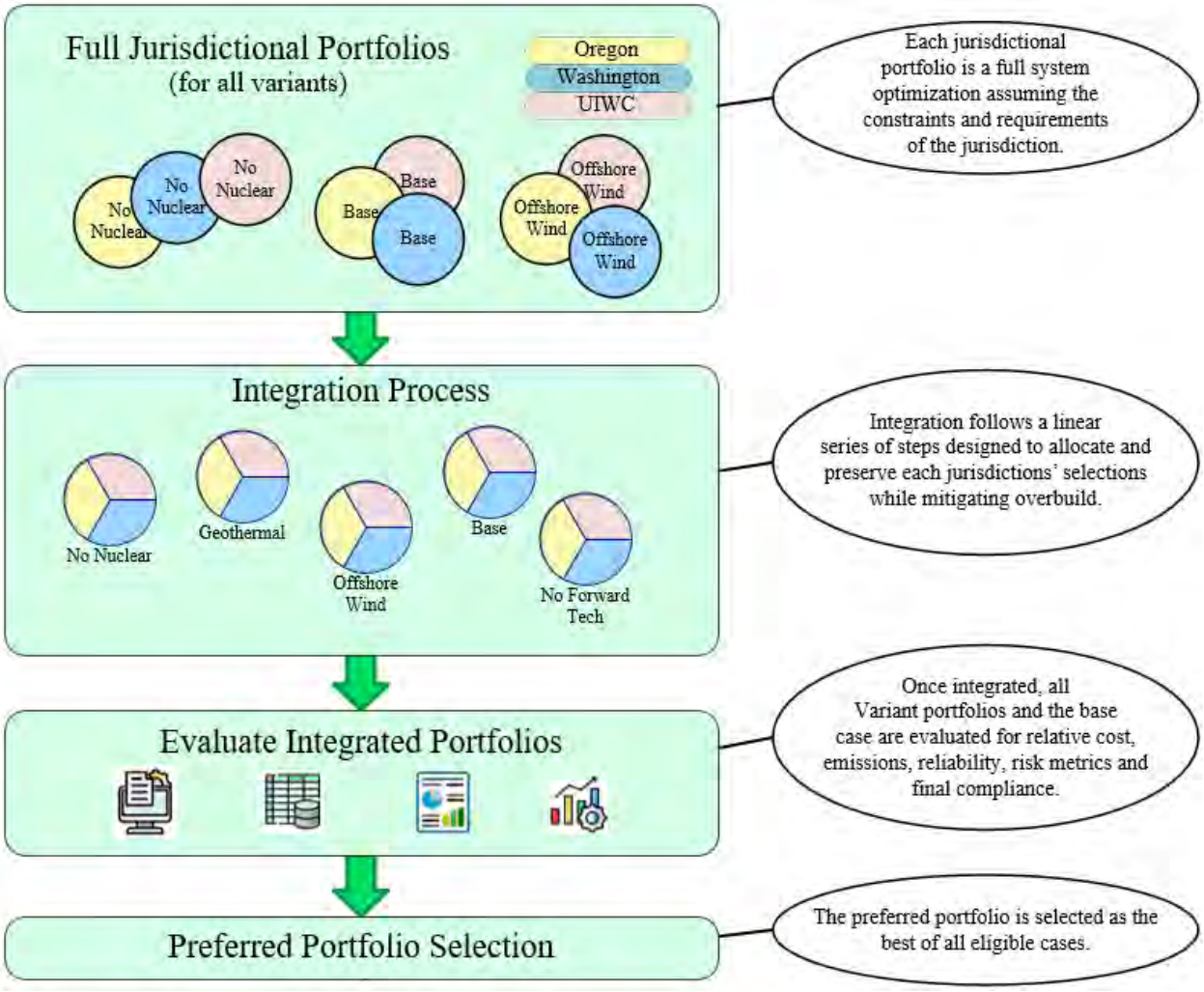
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio includes continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The 2025 IRP preferred portfolio builds upon resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that forthcoming RFPs as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium$^{TM}$ demonstration project, anticipated to achieve online status by the end of 2031. Over the planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind, and 5,912 MW of new solar, of which 1,147 MW is small-scale.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, and additional upgrades that increase transfer and interconnection capability on the west side of PacifiCorp's system.
- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation were converted to natural gas where the option was available.
- In the 2025 IRP, four factors related to emitting resources drive a reduction in $CO_2$ emissions after 2025. These factors are retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities (influenced by additions of renewable resources and energy storage), and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially because of renewable resource additions but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

## Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. As illustrated in Figure 9.1, the final preferred portfolio selection is informed by all relevant modeling results.

**Figure 9.1 – Portfolio Integration and Selection Workflow**




This chapter also presents discussion of Oregon's compliance position in the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic analysis is also discussed in Volume II, Appendix H (Stochastics).

## Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 9.1 below shows the various phases of the Oregon MN initial jurisdictional run to show how iterative jurisdictional portfolios were evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase was selected for integration. In Table 9.1, phase 17 was selected as the Oregon initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $26,298 million, and the stream of unserved energy costs that led to a total cost of $0 and had no unserved energy after 2027. Other phases which were considered were phase 11, phase 15, and phase 5, however the higher PVRR of phases 15 and 5, and the fact that phase 17 was more WRAP compliant than phase 11 led to phase 17 being selected.

**Table 9.1 – Iterative phases of Oregon MN portfolio**

| Phase | Jurisdiction | Price-Policy | 21 Year PVRR | Unserved Energy Cost |
|---|---|---|---|---|
| 0 | OR | Medium Gas, No CO2 | 26,108 | 1 |
| 1 | OR | Medium Gas, No CO2 | 26,809 | 0 |
| 2 | OR | Medium Gas, No CO2 | 26,314 | 0 |
| 3 | OR | Medium Gas, No CO2 | 26,353 | 1 |
| 4 | OR | Medium Gas, No CO2 | 26,405 | 0 |
| 5 | OR | Medium Gas, No CO2 | 26,372 | 0 |
| 6 | OR | Medium Gas, No CO2 | 26,370 | 1 |
| 7 | OR | Medium Gas, No CO2 | 26,343 | 0 |
| 8 | OR | Medium Gas, No CO2 | 26,442 | 1 |
| 9 | OR | Medium Gas, No CO2 | 26,365 | 0 |
| 10 | OR | Medium Gas, No CO2 | 26,498 | 2 |
| 11 | OR | Medium Gas, No CO2 | 26,298 | 0 |
| 12 | OR | Medium Gas, No CO2 | 26,461 | 1 |
| 13 | OR | Medium Gas, No CO2 | 26,366 | 0 |
| 14 | OR | Medium Gas, No CO2 | 26,447 | 1 |
| 15 | OR | Medium Gas, No CO2 | 26,361 | 0 |
| 16 | OR | Medium Gas, No CO2 | 26,388 | 2 |
| 17 | OR | Medium Gas, No CO2 | 26,298 | 0 |
| 18 | OR | Medium Gas, No CO2 | 26,463 | 1 |
| 19 | OR | Medium Gas, No CO2 | 27,058 | 0 |

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal $CO_2$ policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy $CO_2$ policy assumptions, resulting in uniquely optimized combinations of resources, transmission, and thermal retirement options.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

## Jurisdictional Shares of the Preferred Portfolio

Table 9.2 through Table 9.4 present each jurisdiction's assumed *share* of total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

## Table 9.2 – Oregon Share[1, 2, 3]

| OR Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Nuclear | - | - | - | - | - | - | - | 130 | - | - | - | - | - | - | - | - | - | - | - | - | - | 130 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 40 |
| DSM - Energy Efficiency | - | - | 97 | 101 | 107 | 114 | 115 | 110 | 113 | 108 | 109 | 111 | 110 | 106 | 102 | 116 | 123 | 107 | 114 | 92 | 90 | 2,044 |
| DSM - Demand Response | - | 0 | - | 48 | 16 | 7 | - | 5 | 1 | 3 | 3 | 11 | - | 11 | 4 | 23 | 4 | - | 9 | - | 8 | 153 |
| Renewable - Wind | - | - | - | 16 | 445 | 939 | - | 1 | - | 22 | 260 | 30 | 131 | 28 | 0 | 282 | 37 | - | 15 | - | 72 | 2,278 |
| Renewable - Utility Solar | - | - | - | 167 | 135 | 1,268 | 136 | 180 | 302 | 169 | 10 | - | 0 | 0 | 416 | 78 | 9 | - | - | 148 | 56 | 3,074 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | 0 | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Battery, < 8 hour | - | - | 1 | 280 | 100 | 128 | - | 119 | 39 | 210 | 20 | 47 | - | 46 | - | 107 | 55 | - | - | - | - | 1,152 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 272 | 88 | - | - | - | - | - | 7 | 79 | 33 | 934 | 102 | 210 | 397 | 192 | 353 | 2,667 |
| **Potential Solar Acceleration[2]** | | | | ***794*** | | ***(794)*** | | | | | | | | | | | | | | | | |

## Table 9.3 – Washington Share[4]

| WA Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Nuclear | - | - | - | - | - | - | - | 32 | - | - | - | - | - | - | - | - | - | - | - | - | - | 32 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | - | 0 | 13 | 16 | 15 | 17 | 18 | 18 | 19 | 19 | 20 | 19 | 19 | 15 | 14 | 12 | 11 | 11 | 10 | 8 | 7 | 280 |
| DSM - Demand Response | - | 0 | - | 15 | 2 | 2 | - | - | - | - | - | 8 | - | 6 | 1 | 1 | 1 | - | 1 | - | 14 | 51 |
| Renewable - Wind | - | - | - | 5 | 148 | 313 | - | - | - | 7 | 87 | 10 | 44 | 9 | 0 | 94 | 12 | - | 5 | - | 24 | 758 |
| Renewable - Utility Solar | - | - | - | 56 | 45 | 423 | 45 | 60 | 101 | 56 | 3 | - | 0 | 0 | 139 | 26 | 3 | - | - | 49 | 19 | 1,025 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 0 |
| Renewable - Battery, < 8 hour | - | - | - | 865 | 114 | 168 | - | - | - | - | - | - | - | 129 | 67 | 7 | 12 | - | 5 | - | - | 1,367 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 238 | 3 | 3 | 4 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 298 |
| **Potential Solar Acceleration[4]** | | | | ***212*** | | ***(212)*** | | | | | | | | | | | | | | | | |

[1] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[2] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving compliance with Oregon's clean energy compliance requirements, PacifiCorp's 2025 CEP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.2. For more details, please refer to Appendix P (Oregon Clean Energy Update)
[3] Planned Energy efficiency and demand response selections in 2025 and 2026 are not presented in Tables 9.2 through 9.4.

**Table 9.4 – Utah, Idaho, Wyoming, and California Share**

| UIWC Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Nuclear | - | - | - | - | - | - | - | 338 | - | - | - | - | - | - | - | - | - | - | - | - | - | 338 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | - | 0 | 99 | 103 | 117 | 130 | 196 | 163 | 167 | 168 | 170 | 185 | 218 | 193 | 177 | 172 | 170 | 197 | 114 | 106 | 86 | 2,931 |
| DSM - Demand Response | - | 1 | - | - | 2 | 111 | 99 | - | - | - | - | 2 | 112 | - | - | 0 | 57 | 106 | 19 | 26 | 30 | 566 |
| Renewable - Wind | - | - | - | - | 200 | 200 | 344 | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 744 |
| Renewable - Utility Solar | - | - | - | - | - | - | 668 | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 668 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 1 | - | 27 | - | - | - | - | - | - | - | 0 | - | - | - | - | 713 | - | 459 | 733 | 1,933 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | 104 | - | - | - | 105 |

## Full Jurisdictional Portfolios

Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration.

The following portfolios shown in Table 9.5 through Table 9.7 report the entirety of each jurisdictional portfolio's selections when planning for the entire system, which were then integrated into the preferred portfolio. This same integration process is used to develop integrated portfolios specific to each variant and price-policy scenario, and the preferred portfolio is selected based on the results for the integrated portfolios.

[4] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving CETA compliance, PacifiCorp's 2025 CEIP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.3.For more details, please refer to Appendix O (Washington Clean Energy Action Plan)

# Table 9.5 – Oregon Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| **Resource** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 201 | 209 | 220 | 237 | 306 | 280 | 283 | 280 | 300 | 309 | 333 | 303 | 283 | 291 | 266 | 286 | 252 | 230 | 189 | 5,239 |
| DSM - Demand Response | 18 | 2 | - | 53 | 17 | 9 | 53 | 5 | 1 | 3 | 3 | 11 | 259 | 15 | 50 | 23 | 4 | 100 | 9 | 50 | 25 | 710 |
| Renewable - Wind | - | - | - | 21 | 260 | 1,066 | 100 | 51 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 2,668 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 122 | 99 | 1,871 | 19 | 220 | 315 | 225 | 13 | - | - | - | 554 | 104 | 12 | - | - | 197 | 75 | 3,826 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 876 | 255 | 228 | 31 | 119 | 39 | 210 | 20 | 83 | - | 104 | 100 | 314 | 58 | - | 2 | - | - | 2,439 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 17 | 224 | - | - | - | - | - | 241 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 134 | - | - | - | - | - | - | - | 59 | 4 | 752 | 128 | - | 341 | - | 59 | 1,477 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (1,387) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,949) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | - | 0 |
| Coal - Gas Conversions | - | 46 | - | - | - | 687 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (418) | 315 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (79) | (79) |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **110** | **153** | **201** | **1,026** | **523** | **3,444** | **302** | **1,193** | **664** | **765** | **713** | **575** | **667** | **795** | **1,008** | **2,084** | **249** | **(140)** | **581** | **387** | **(18)** | |

# Table 9.6 – Washington Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 224 | 235 | 215 | 234 | 289 | 287 | 291 | 290 | 316 | 323 | 356 | 324 | 304 | 293 | 278 | 302 | 268 | 234 | 186 | 5,430 |
| DSM - Demand Response | 18 | 2 | 2 | 197 | 5 | 17 | - | - | - | - | - | 43 | - | 17 | 24 | 8 | 5 | 331 | 31 | 27 | 107 | 834 |
| Renewable - Wind | - | - | - | - | 1,607 | - | 260 | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,868 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 201 | 138 | 463 | 1,437 | 770 | 527 | 418 | 772 | 249 | 100 | 1 | - | - | - | - | - | - | - | 5,076 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 38 | 856 | 232 | 1,376 | - | - | - | - | - | - | - | 129 | 67 | 66 | 129 | 149 | 646 | 170 | 1,357 | 5,215 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (906) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (2,679) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (3,241) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (526) | 0 |
| Coal - Gas Conversions | - | 311 | - | - | 205 | 1,979 | (330) | - | - | - | - | - | - | - | - | - | - | - | - | - | (448) | 1,717 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **110** | **418** | **264** | **548** | **2,074** | **1,669** | **1,447** | **1,558** | **818** | **705** | **1,088** | **615** | **356** | **439** | **395** | **367** | **14** | **782** | **898** | **198** | **656** | |

# Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

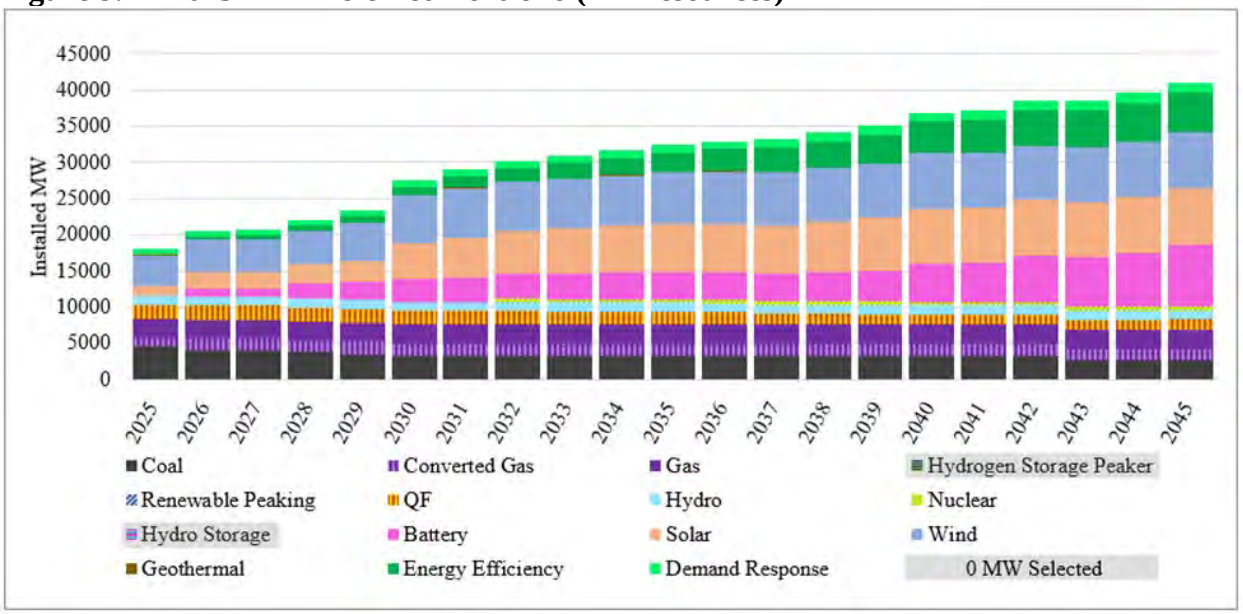
| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 164 | 170 | 182 | 196 | 270 | 236 | 247 | 251 | 261 | 286 | 312 | 284 | 278 | 257 | 252 | 283 | 216 | 200 | 165 | 4,691 |
| DSM - Demand Response | 18 | 2 | - | 2 | 7 | 112 | 99 | - | - | - | 5 | 39 | 115 | 3 | - | 4 | 70 | 106 | 43 | 30 | 32 | 687 |
| Renewable - Wind | - | - | - | - | 306 | 684 | 344 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,334 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 153 | 12 | 79 | 668 | - | 31 | 123 | 133 | 3 | - | - | - | 2 | - | - | - | 65 | - | 1,269 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 193 | 71 | 224 | - | - | - | - | 85 | 171 | 4 | 474 | 249 | 140 | 469 | 713 | 896 | 1,097 | 733 | 5,519 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 104 | - | - | - | 104 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| Coal - Gas Conversions | - | 251 | - | - | 144 | - | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 239 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (5) | - | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **110** | **358** | **164** | **263** | **394** | **874** | **1,172** | **736** | **278** | **371** | **484** | **499** | **331** | **729** | **527** | **403** | **393** | **1,206** | **426** | **1,157** | **910** | |

## The 2025 IRP Preferred Portfolio

The preferred portfolio is selected from among all of the variant and price-policy portfolios after integration. PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear. The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources are scheduled to come online in the 2024 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by fall 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912 MW of new solar.

**Figure 9.2 – 2025 IRP Preferred Portfolio (All Resources)**




* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

New since the 2023 IRP, the 2025 IRP preferred portfolio includes a number of smaller incremental upgrades to enhance transfer capability, including lines between southern Utah and the Wasatch Front in Utah, Walla Walla and Yakima in Washington, Walla Walla and Deschutes County in Oregon, and Summer Lake and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Eight out of the fourteen transmission selections are expected to increase interconnection capability only, while the other six transmission selections provide both interconnection capability and increased transfer capability among the transmission areas modeled in the IRP. Table 9.8 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio.

**Table 9.8 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]**

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| **2026** | Utah South - Wasatch Front: 138 kV reinforcement #1 | 250 | 250 | 250 | 30 | 100% | Utah South | Wasatch Front |
| **2028** | Cluster 1 Area 11: Willamette Valley | 0 | 0 | 199 | 14 | 100% | n/a | n/a |
| | Cluster 1 Area 14: Summer Lake | 400 | 400 | 400 | 111 | 100% | Summer Lake | Hemingway |
| | Cluster 1/2/3: Walla Walla | 0 | 0 | 393 | 328 | 100% | n/a | n/a |
| | Serial queue: Central Oregon | 0 | 0 | 152 | 4 | 100% | n/a | n/a |
| | Serial/Cluster 1/2: Yakima | 0 | 0 | 628 | 64 | 100% | n/a | n/a |
| | Utah South - Wasatch Front: 138 kV reinforcement #2 | 200 | 200 | 200 | 12 | 100% | Utah South | Wasatch Front |
| **2029** | Cluster 2 Area 23: Willamette Valley | 0 | 0 | 393 | 2 | 100% | n/a | n/a |
| **2030** | Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV | 1,500 | 1,500 | 670 | 1,283 | 100% | Summer Lake | Central OR |
| | Walla Walla - Yakima 230 kV | 400 | 400 | 400 | 142 | 100% | Walla Walla | Yakima |
| **2031** | Serial through Cluster 1 Area 13: Southern Oregon | 0 | 0 | 231 | 42 | 100% | n/a | n/a |
| **2032** | Cluster 1 Area 12: Southern Oregon | 0 | 0 | 300 | 303 | 100% | n/a | n/a |
| **2033** | Cluster 2 Area 18: Central Oregon 500 kV Substation | 0 | 0 | 518 | 372 | 100% | n/a | n/a |
| **2039** | Walla Walla - Central Oregon 500 kV | 1,500 | 1,500 | 670 | 1,463 | 100% | Walla Walla | Central OR |
| **Grand Total** | | **4,250** | **4,250** | **5,404** | **4,169** | | | |

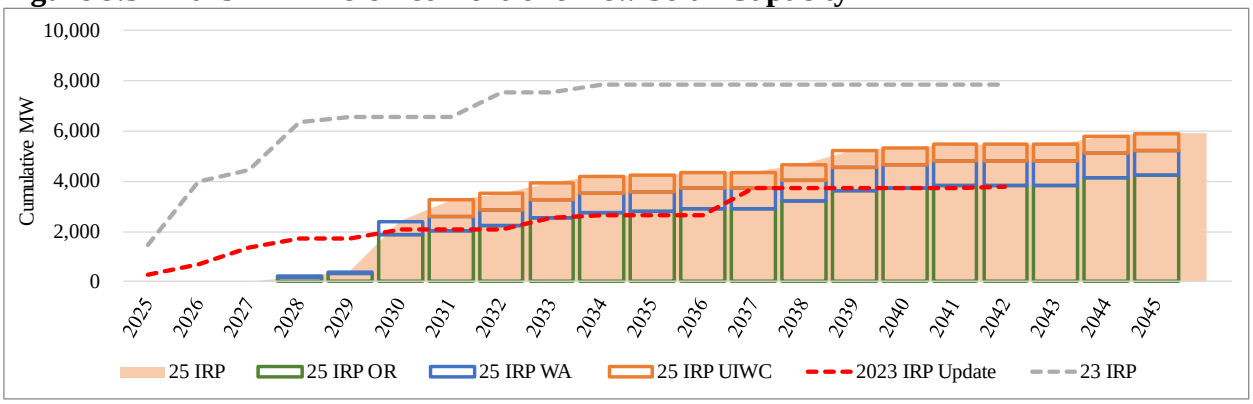
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

## New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 9.3.

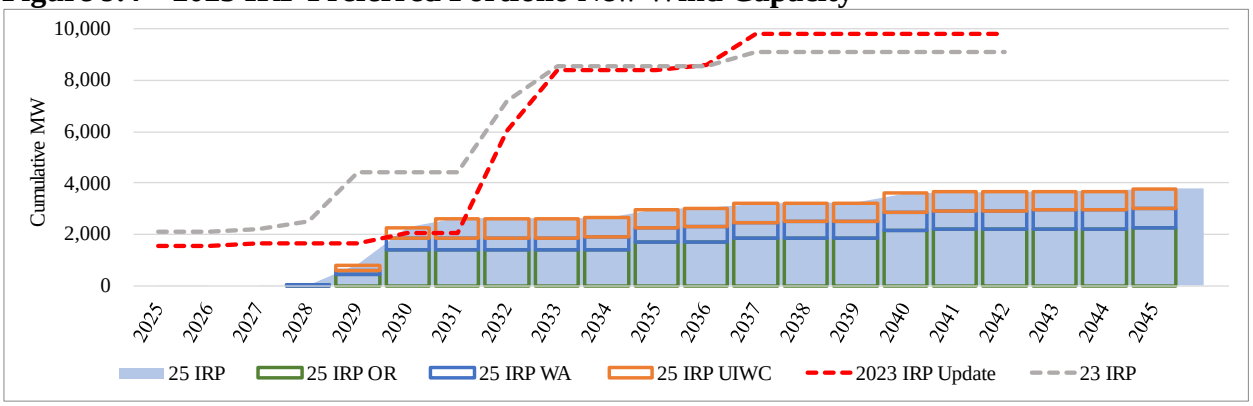
**Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity**



## New Wind Resources

As shown in Figure 9.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

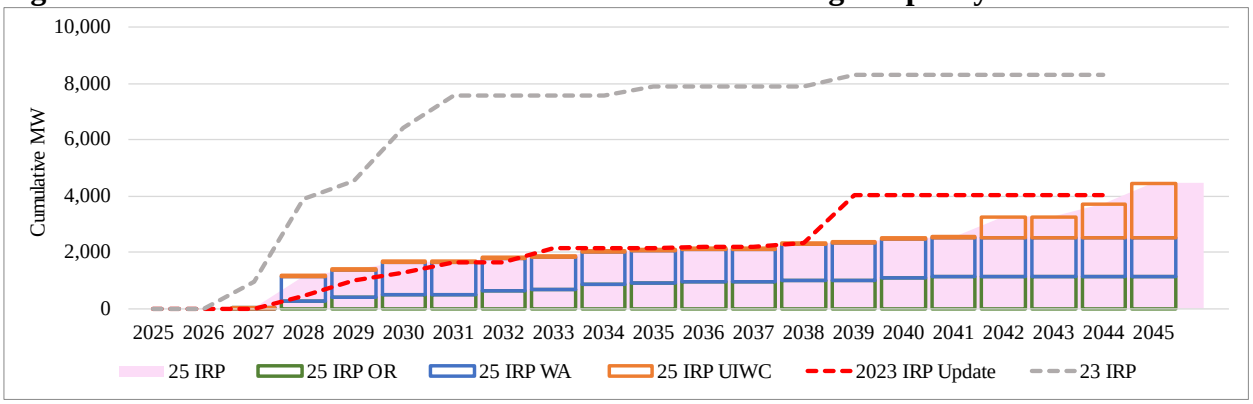
**Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity**




## New Storage Resources

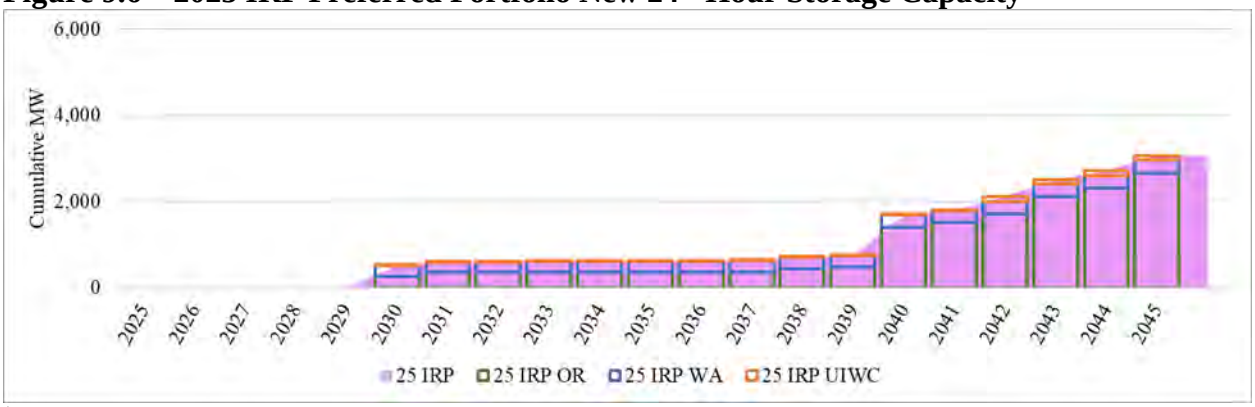
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of storage with at least 24 hours duration by the end of 2030 and growing to 616 MW by 2035 and 3,073 MW by 2045. Cumulative storage selections, inclusive of both short and long duration resources, total 7,524 MW by 2045.

**Figure 9.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]**




[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not categorized as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 9.5 include a minimal amount of intermediate duration storage.

**Figure 9.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]**

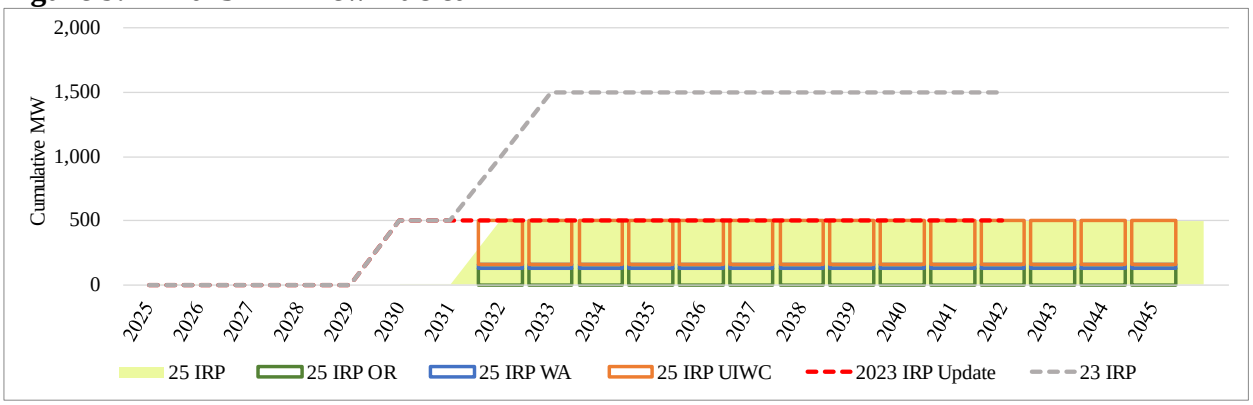



[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

## New Nuclear Resources

The 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.7, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by fall 2031.

**Figure 9.7 – 2025 IRP New Nuclear[1]**



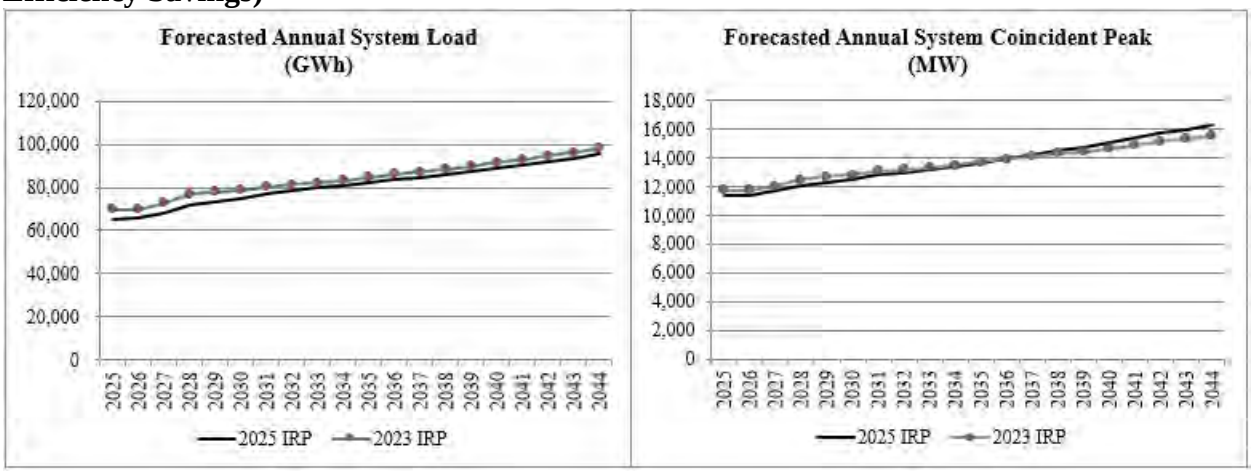

[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

## Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over

the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, thus lowering the commercial forecast.[5]

**Figure 9.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)**

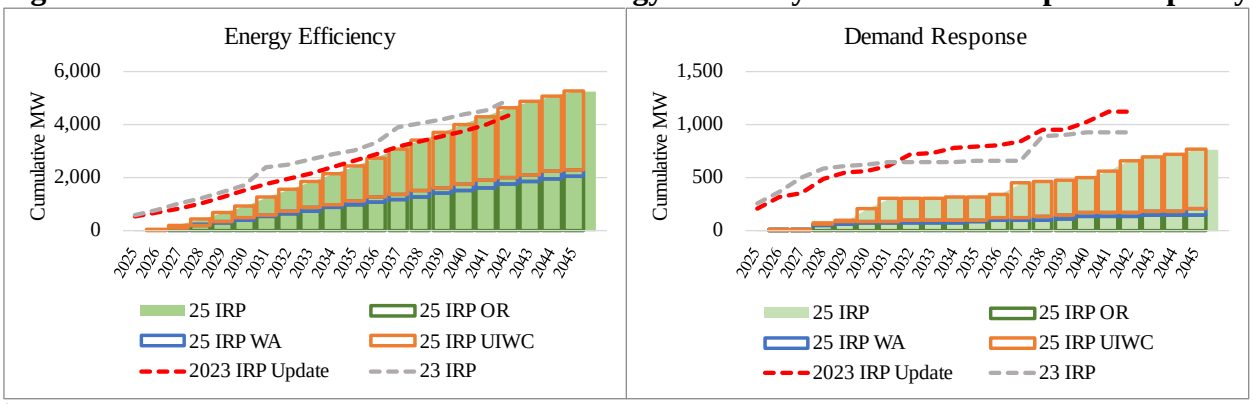



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 IRP preferred portfolio totals 5,436 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.9 compares cumulative demand response program capacity in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2025 IRP has a cumulative capacity of demand response programs totaling 515 MW by 2040. By year-end 2045, the 2025 IRP preferred portfolio has a cumulative capacity of demand response programs totaling 789 MW.

[5] A different approach is needed to protect existing customers from sizeable resource and transmission infrastructure investment costs associated with certain new large loads. Consequently, these loads fall outside of the traditional planning process. Should those loads materialize, we are working with certain large customers to ensure they can bring sufficient resources and are prepared to pay for the incremental transmission upgrades required to serve them.

**Figure 9.9 – 2025 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity**




[1] Energy efficiency and demand response in the 2023 IRP began escalating two years prior to when escalation begins in the 2025 IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP, the end of the planning horizon.

## Wholesale Power Market Prices and Purchases

Figure 9.11 illustrates that the 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 9.11 reports that the 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Market transactions in the 2025 IRP are purely economic as market purchases do not contribute to capacity like they did in the 2023 IRP and 2023 IRP Update. In the 2023 IRP and 2023 IRP Update, market purchases were limited to 1,000 MW in the winter and 500 MW in the summer. For the 2025 IRP, economic market purchases for energy could be made up to transmission limits, but market purchases were not allowed on the top five load days during peak hours in peak seasons and could never be used for capacity. Refer to Chapter 5: Reliability and Resiliency for additional details.

**Figure 9.10 – 2025 IRP Preferred Portfolio Market Purchases**

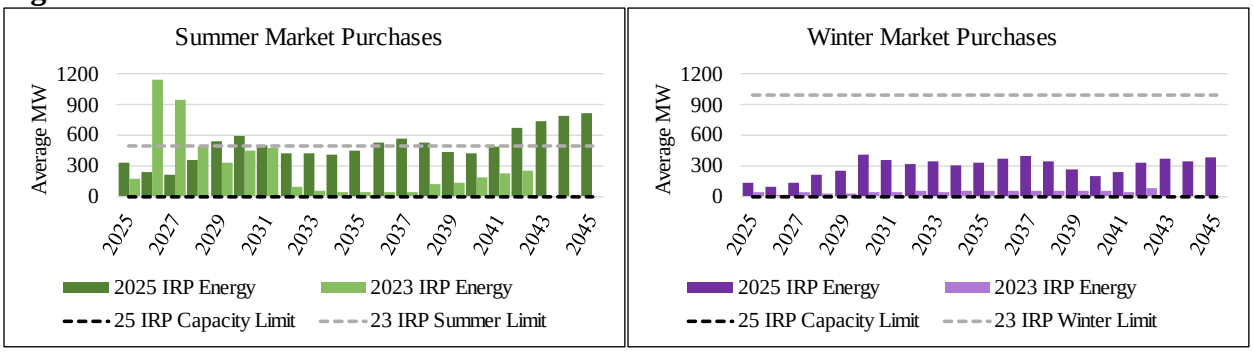
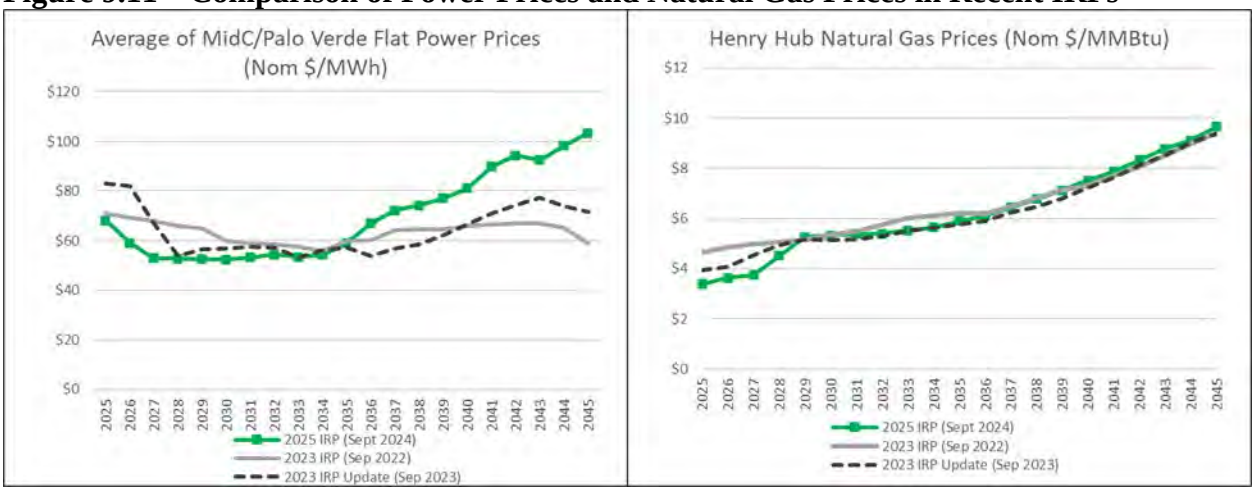


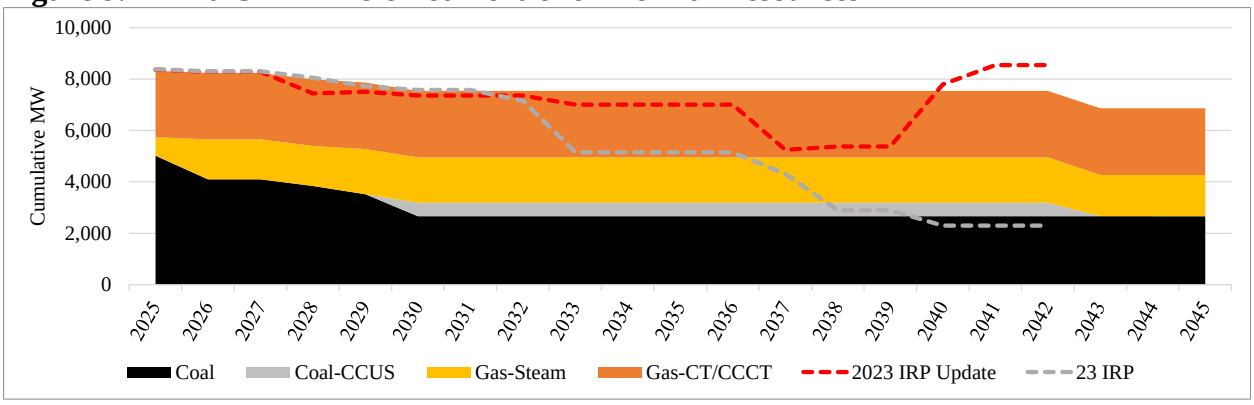
**Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs**




## Coal and Gas Retirements/Gas Conversions

Coal-fuel plants have been an important contributor to PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that have enabled the company to reduce fuel consumption, associated costs and emissions, and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 9.12, the 2025 IRP converts 562 MW of coal-fueled generation to natural gas fueled, exits PacifiCorp's share in 386 MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

**Figure 9.12 – 2025 IRP Preferred Portfolio Thermal Resources**




A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 9.9. Also shown in Table 9.9 are

the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[6]

**Table 9.9 – 2025 IRP Coal Resource Results**

| Majority-Owned Coal | | | |
|---|---|---|---|
| Unit | 2025 IRP Retirement Year | | 2023 IRP Retirement Year |
| | Selected w/o 111(d) Regulation | Selected w/ 111(d) Regulation | As Selected |
| Dave Johnston 1 & 2 | Not retired (Gas conversion 2029) | No change | 2028 |
| Dave Johnston 3 | 2027 (Clean air compliance) | No change | 2027 (Clean air compliance) |
| Dave Johnston 4 | Not retired | Not retired (Gas conversion 2030) | 2039 |
| Hunter 1 | Not retired | 2032 | 2031 |
| Hunter 2 & 3 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Huntington 1 & 2 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Jim Bridger 1 & 2 | Not retired (Gas conversion 2024) | No change | 2037 (Gas conversion 2024) |
| Jim Bridger 3 & 4 | 2042 (CCS conversion 2030) | No change | 2037 (Gas conversion 2030) |
| Naughton 1 | 2042 (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Naughton 2 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Wyodak | Not retired | 2032 | 2039 |

| Minority-Owned Coal | | |
|---|---|---|
| Unit | 2025 IRP Retirement Year | 2023 IRP Retirement Year |
| | As Input | As Input |
| Colstrip 3 | 2025 (Transfer capacity to unit 4) | 2025 (Transfer capacity to unit 4) |
| Colstrip 4 | 2029 (PacifiCorp exit) | 2029 (PacifiCorp exit) |
| Craig 1 | 2025 (Assumed end of life) | 2025 (Assumed end of life) |
| Craig 2 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 1 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 2 | 2027 (Assumed end of life) | 2027 (Assumed end of life) |

## Carbon Dioxide Equivalent Emissions

The 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total ($CO_2e$) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new battery storage resources, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the top in Figure 9.13 compares projected annual $CO_2e$ emissions across the 2025 IRP and the 2023 IRP preferred portfolios and is inclusive of emissions attributed to market purchases. In the current 2025 IRP preferred portfolio, emissions are generally higher than projected in the 2023 IRP. This relative increase is primarily the result of two differences in modeling assumptions. In the 2023 IRP, a medium CO2 price was included in the expected price-

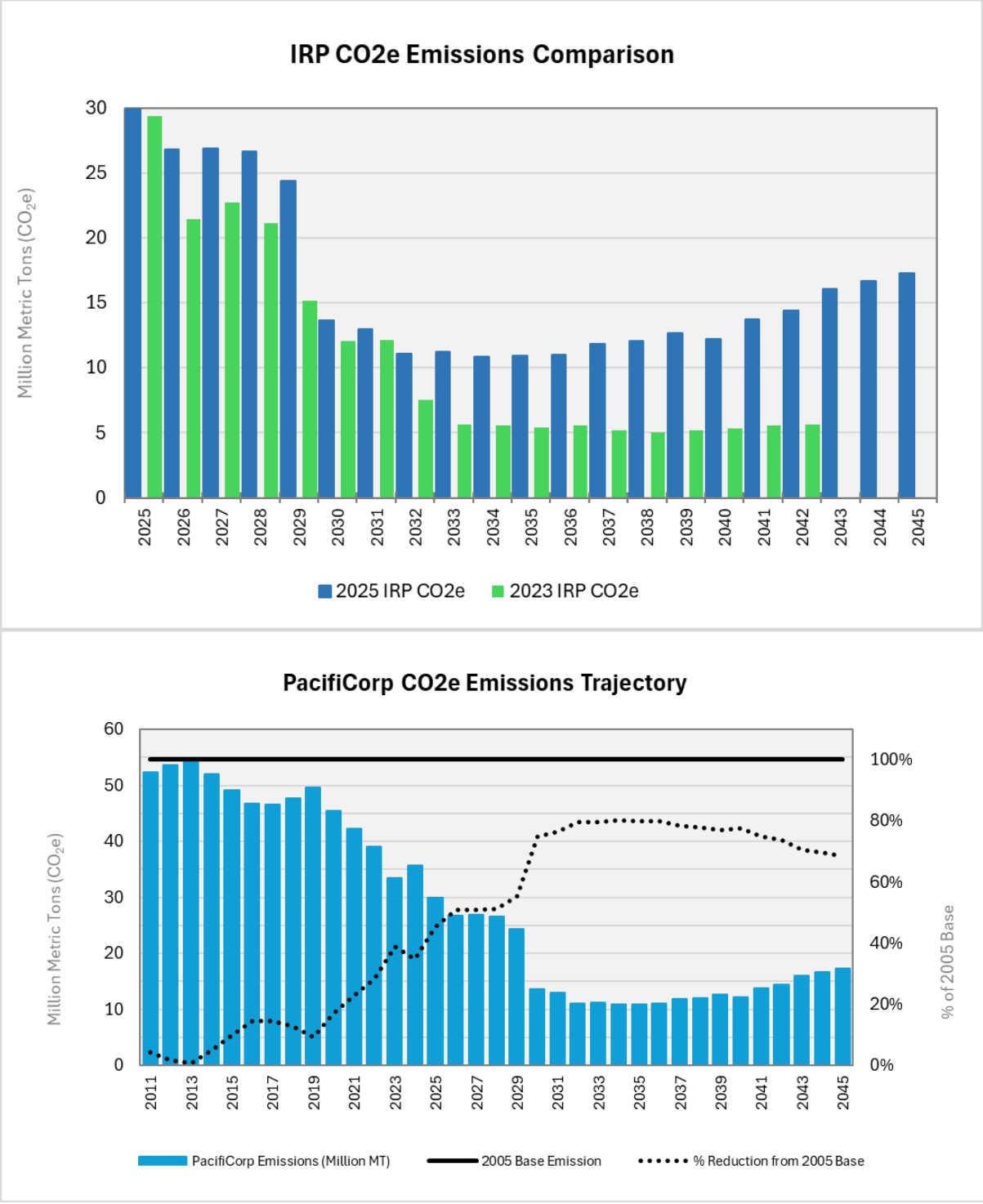
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

policy scenario used to forecast emissions. No CO2 price was included in the dispatch of the 2025 IRP preferred portfolio used to forecast emissions. The 2023 IRP also modeled the EPA's proposed implementation of the Ozone Transport Rule as a significant dispatch target on emissions. No dispatch target was included in the expected price-policy scenario used to forecast emissions in the 2025 IRP. The MR (medium gas price with at-risk federal regulation) price-policy scenario accounts for the effects of possible federal policy, and the portfolio optimized and dispatched under the MR price-policy scenario is a better comparison to the 2023 IRP preferred portfolio.

The difference in emissions between the 2023 IRP and the 2025 IRP is also partly due to an increase in unspecified market purchases, which are assigned a default emission factor of 0.428 MT CO2e/MWh. This default factor, often established by state regulations and widely used in GHG compliance reporting across multiple states, remains constant throughout the planning period. However, energy industry experts believe the market is trending toward lower emissions as renewable energy and storage capacity expand. As more renewables enter the market, overall emissions are expected to decline, translating to a lower emission factor. PacifiCorp is actively engaging with states to discuss updating this default emission factor to better reflect the market's transition to cleaner energy. Finally, the difference in emissions from the 2023 IRP reflects the 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing existing coal plants to operate through the planning period at a reduced capacity factor. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals.

The bottom chart in Figure 9.13 presents historical data and assigns emissions to unspecified market purchases at a rate of 0.428 metric tons $CO_2$ equivalent per MWh – with no credit to market sales. It also accounts for emissions from specified purchases. The graph shows that system CO2e emissions have declined by approximately 45% in 2025, 75% in 2030, and 77% in 2040, compared to a 2005 baseline of 54.6 million metric tons. In the final five years of the planning horizon, emissions increase moderately due to the factors outlined above.

**Figure 9.13 – 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]**




[1] PacifiCorp $CO_2$ equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in $CO_2$ equivalent. Market purchases are assigned a default emission factor (0.428 metric tons $CO_2e$/MWh) – emissions from sales are not removed.

## Renewable Portfolio Standards

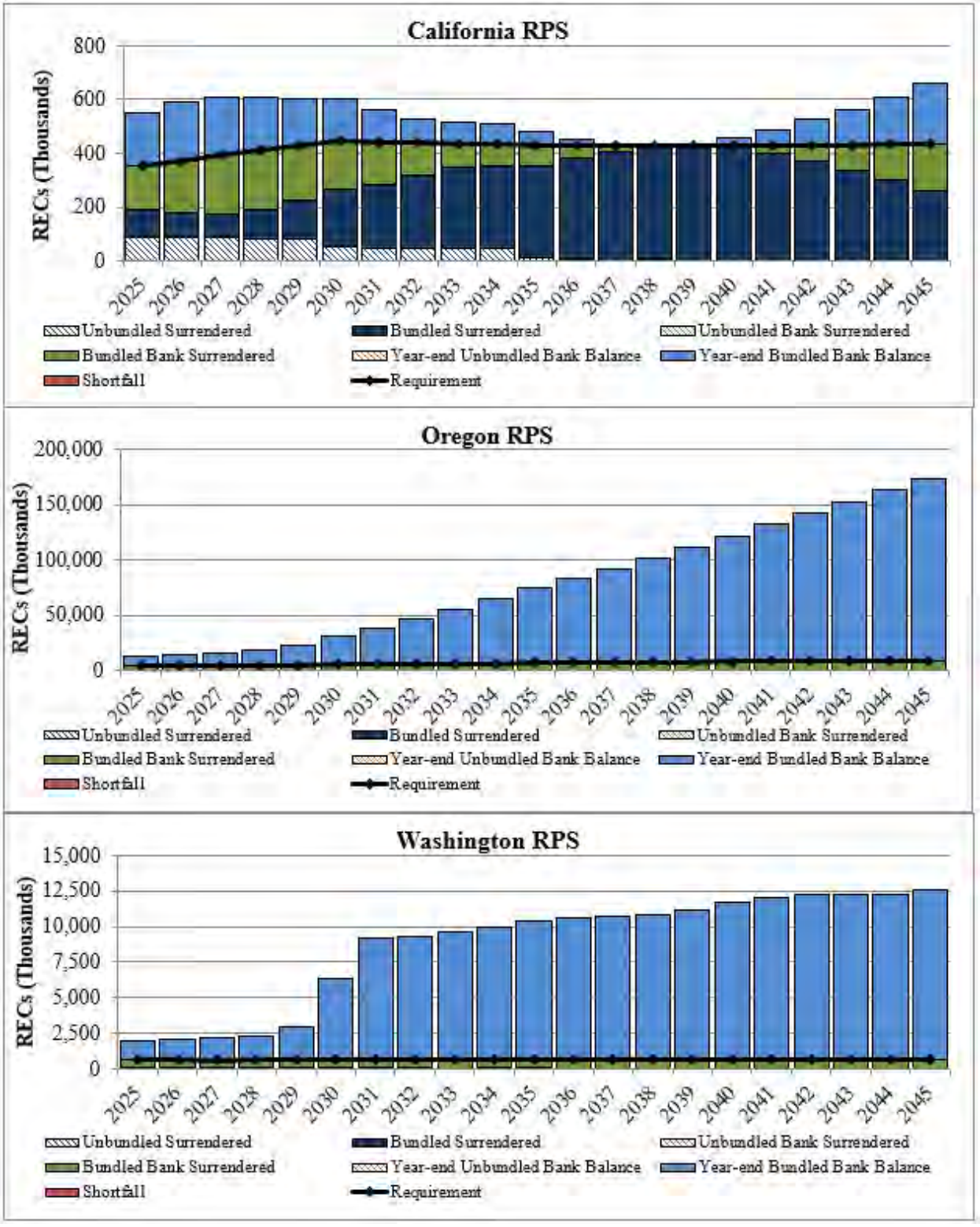
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2045 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a share of renewable resources across PacifiCorp's system; however, Washington may also benefit from the situs allocation of new renewable resources as necessary for compliance.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as unbundled REC purchases at various points throughout the 2025 IRP study period. The increasing RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the long term. The company will rely on a combination of new renewable resources from the preferred portfolio and unbundled RECs to meet future shortfalls.

Although not depicted in Figure 9.14, PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the 2025 IRP preferred portfolio.

**Figure 9.14 – Annual State RPS Compliance Forecast**



## Oregon HB 2021 Compliance

In 2021, Oregon adopted House Bill 2021, an energy policy seeking to reduce emissions from electric generation facilities used to serve customers in the state. HB 2021 sets targets to reduce emissions associated with Oregon retail sales from a baseline, calculated as the average emissions reported from years 2010 through 2012, by 80 percent in 2030, 90 percent by 2035 and 100 percent by 2040. For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalents ($CO_2e$) to 1.79 MMT $CO_2e$ by 2030, 0.89 MMT $CO_2e$ by 2035, and zero by 2040. The law also increased Oregon's small-scale renewable energy project purchase requirement from 8 to 10 percent by 2030.

The 2025 IRP preferred portfolio was developed to incorporate resources specifically selected to meet all state-specific requirements, including Oregon's greenhouse gas emission reduction targets defined by HB 2021. PacifiCorp also modeled the small-scale renewable portfolio requirement to ensure that at least 10 percent of Oregon-allocated capacity will be small-scale (20 MW or less), in each year from 2030 onwards. For more information on Oregon's planning requirements and the compliance position of the preferred portfolio, refer to Volume II, Appendix P (Oregon Clean Energy Update).

## Capacity and Energy

Figure 9.15 and Figure 9.16 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon dispatch under base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[7] On an energy basis, coal generation drops below 20 percent in 2030 and remains below 15 percent through the end of the planning period. On a capacity basis, coal resources drop below 10 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, and DSM resources.

[7]The projected PacifiCorpIRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp'sIRP preferred portfolio energy mix includes owned resources and purchases from third parties.

**Figure 9.15 – Projected Energy Mix with Preferred Portfolio Resources**

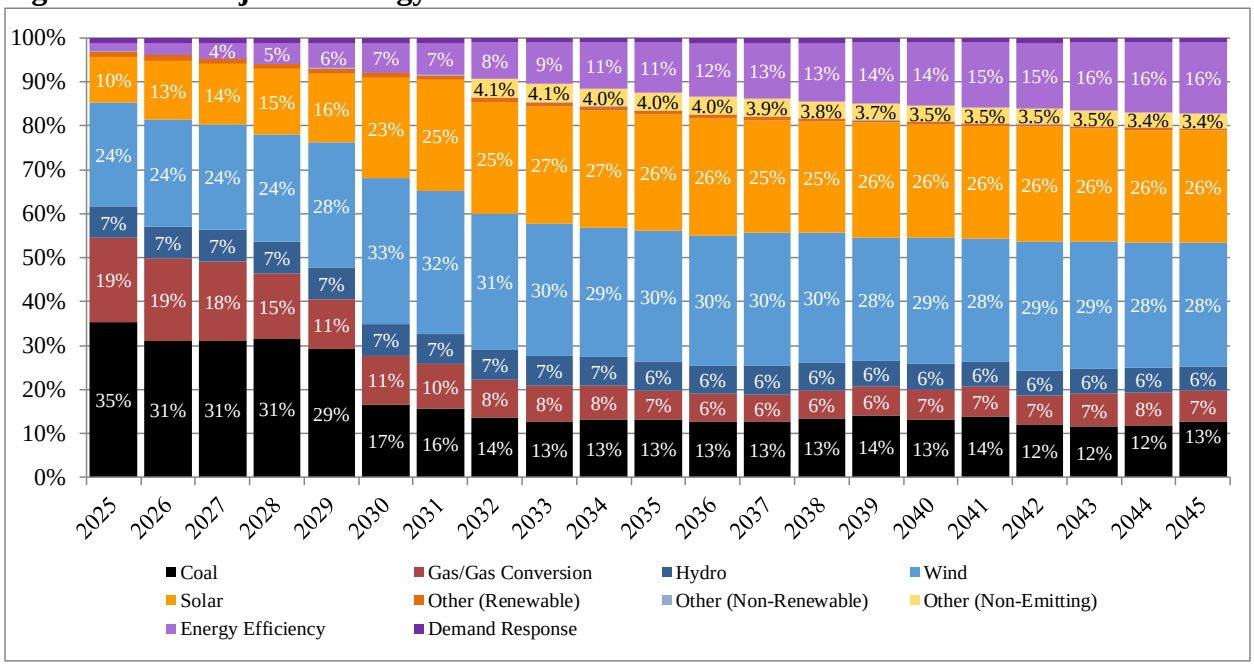
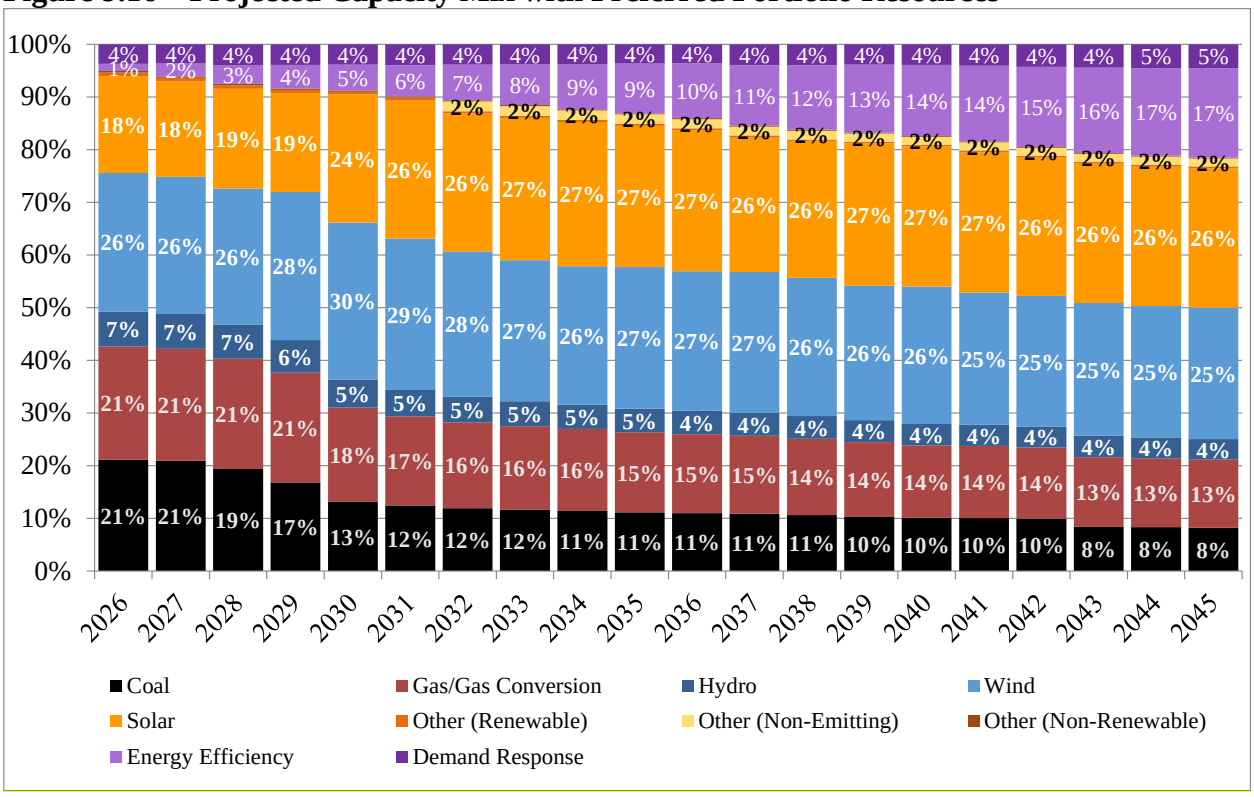



**Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources**



## Detailed Preferred Portfolio

Table 9.10 provides line-item detail of PacifiCorp's 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon. Table 9.11 shows jurisdictional resource selections of PacifiCorp's 2025 IRP preferred portfolio. Table 9.12 and Table 9.13 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon. Table 9.14 and Table 9.15 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

# Table 9.10 – PacifiCorp's 2025 IRP Preferred Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 209 | 220 | 239 | 261 | 329 | 291 | 299 | 295 | 299 | 315 | 347 | 314 | 293 | 301 | 303 | 315 | 238 | 205 | 182 | 5,436 |
| DSM - Demand Response | 18 | 2 | - | 63 | 21 | 120 | 99 | 5 | 1 | 3 | 3 | 21 | 112 | 18 | 5 | 24 | 61 | 106 | 29 | 26 | 52 | 789 |
| Renewable - Wind | - | - | - | 21 | 794 | 1,452 | 344 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 3,782 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 849 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 4,765 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 1,146 | 242 | 296 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | 713 | 5 | 459 | 733 | 4,451 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 319 | 402 | 197 | 358 | 3,073 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 406 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **110** | **464** | **209** | **1,417** | **1,353** | **4,229** | **1,505** | **1,177** | **772** | **783** | **716** | **559** | **546** | **904** | **956** | **1,857** | **331** | **1,453** | **(31)** | **994** | **1,530** | |

## Table 9.11 – Preferred Portfolio with Jurisdictional Resource Selections

| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | **500** | - | - | - | - | - | - | - | - | - | - | - | - | - | **500** |
| OR | - | - | - | - | - | - | - | 130 | - | - | - | - | - | - | - | - | - | - | - | - | - | 130 |
| WA | - | - | - | - | - | - | - | 32 | - | - | - | - | - | - | - | - | - | - | - | - | - | 32 |
| UIWC | - | - | - | - | - | - | - | 338 | - | - | - | - | - | - | - | - | - | - | - | - | - | 338 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **19** | - | **4** | - | **18** | **41** |
| OR | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 40 |
| WA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| UIWC | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | **92** | **89** | **209** | **220** | **239** | **261** | **329** | **291** | **299** | **295** | **299** | **315** | **347** | **314** | **293** | **301** | **303** | **315** | **238** | **205** | **182** | **5,255** |
| OR | - | - | 97 | 101 | 107 | 114 | 115 | 110 | 113 | 108 | 109 | 111 | 110 | 106 | 102 | 116 | 123 | 107 | 114 | 92 | 90 | 2,044 |
| WA | - | 0 | 13 | 16 | 15 | 17 | 18 | 18 | 19 | 19 | 20 | 19 | 19 | 15 | 14 | 12 | 11 | 11 | 10 | 8 | 7 | 280 |
| UIWC | - | 0 | 99 | 103 | 117 | 130 | 196 | 163 | 167 | 168 | 170 | 185 | 218 | 193 | 177 | 172 | 170 | 197 | 114 | 106 | 86 | 2,931 |
| DSM - Demand Response | **18** | **2** | - | **63** | **21** | **120** | **99** | **5** | **1** | **3** | **3** | **21** | **112** | **18** | **5** | **24** | **61** | **106** | **29** | **26** | **52** | **769** |
| OR | - | 0 | - | 48 | 16 | 7 | - | 5 | 1 | 3 | 3 | 11 | - | 11 | 4 | 23 | 4 | - | 9 | - | 8 | 153 |
| WA | - | 0 | - | 15 | 2 | 2 | - | - | - | - | - | 8 | - | 6 | 1 | 1 | 1 | - | 1 | - | 14 | 51 |
| UIWC | - | 1 | - | - | 2 | 111 | 99 | - | - | - | - | 2 | 112 | - | - | 0 | 57 | 106 | 19 | 26 | 30 | 566 |
| Renewable - Wind | - | - | - | **21** | **794** | **1,452** | **344** | **1** | - | **29** | **347** | **40** | **175** | **37** | - | **376** | **50** | - | **20** | - | **96** | **3,782** |
| OR | - | - | - | 16 | 445 | 939 | - | 1 | - | 22 | 260 | 30 | 131 | 28 | 0 | 282 | 37 | - | 15 | - | 72 | 2,278 |
| WA | - | - | - | 5 | 148 | 313 | - | - | - | 7 | 87 | 10 | 44 | 9 | 0 | 94 | 12 | - | 5 | - | 24 | 758 |
| UIWC | - | - | - | - | 200 | 200 | 344 | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 744 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | **222** | **180** | **1,690** | **849** | **240** | **403** | **225** | **13** | - | **1** | - | **554** | **104** | **12** | - | - | **197** | **75** | **4,765** |
| OR | - | - | - | 167 | 135 | 1,268 | 136 | 180 | 302 | 169 | 10 | - | 0 | 0 | 416 | 78 | 9 | - | - | 148 | 56 | 3,074 |
| WA | - | - | - | 56 | 45 | 423 | 45 | 60 | 101 | 56 | 3 | - | 0 | 0 | 139 | 26 | 3 | - | - | 49 | 19 | 1,025 |
| UIWC | - | - | - | - | - | - | 668 | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 668 |
| Renewable - Small Scale Solar | - | - | - | - | - | **320** | **2** | **18** | **26** | **21** | **30** | **132** | - | **309** | - | - | **110** | - | - | **143** | **36** | **1,147** |
| OR | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | 0 | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| WA | - | - | - | - | - | - | - | - | - | - | - | - | 0 | - | - | - | - | - | - | - | - | 0 |
| UIWC | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | **1,146** | **242** | **296** | - | **119** | **39** | **210** | **20** | **47** | - | **175** | **67** | **113** | **67** | **713** | **5** | **459** | **733** | **4,451** |
| OR | - | - | 1 | 280 | 100 | 128 | - | 119 | 39 | 210 | 20 | 47 | - | 46 | - | 107 | 55 | - | - | - | - | 1,152 |
| WA | - | - | - | 865 | 114 | 168 | - | - | - | - | - | - | - | 129 | 67 | 7 | 12 | - | 5 | - | - | 1,367 |
| UIWC | - | - | 1 | - | 27 | - | - | - | - | - | - | - | 0 | - | - | - | - | 713 | - | 459 | 733 | 1,933 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | **511** | **91** | **3** | **4** | **3** | **4** | **4** | **11** | **83** | **37** | **939** | **107** | **319** | **402** | **197** | **358** | **3,073** |
| OR | - | - | - | - | - | 272 | 88 | - | - | - | - | - | 7 | 79 | 33 | 934 | 102 | 210 | 397 | 192 | 353 | 2,667 |
| WA | - | - | - | - | - | 238 | 3 | 3 | 4 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 298 |
| UIWC | - | - | - | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | 104 | - | - | - | 105 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

# Table 9.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,960 | 3,567 | 3,567 | 3,375 | 3,090 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 |
| Gas | 2,984 | 3,294 | 3,294 | 3,294 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 587 | 613 | 596 | 578 | 561 | 534 | 503 | 487 | 470 | 453 |
| Solar | 342 | 499 | 487 | 475 | 463 | 452 | 440 | 428 | 416 | 404 |
| Other Renewable | 46 | 45 | 44 | 42 | 41 | 40 | 39 | 37 | 36 | 35 |
| Storage | 1 | 939 | 925 | 909 | 894 | 879 | 865 | 849 | 834 | 819 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 405 | 394 | 383 | 372 | 361 | 351 | 340 | 328 | 314 | 301 |
| Demand Response | 451 | 446 | 440 | 452 | 450 | 443 | 429 | 423 | 431 | 425 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (281) | (1,447) | (1,369) | (1,105) | (973) | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **8,571** | **8,426** | **8,443** | **8,470** | **8,433** | **9,171** | **9,087** | **9,024** | **8,973** | **8,909** |
| Additional Proxy/Short-Term Purchases | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 |
| Wind | 0 | 0 | 0 | 0 | 35 | 68 | 124 | 121 | 119 | 117 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 151 | 147 | 143 | 139 |
| Storage | 0 | 0 | 2 | 2 | 25 | 27 | 27 | 27 | 26 | 26 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 457 | 454 | 452 |
| Demand Response | 7 | 7 | 7 | 7 | 8 | 80 | 151 | 149 | 146 | 143 |
| **East Planned Resources** | **7** | **7** | **9** | **9** | **70** | **177** | **455** | **903** | **891** | **879** |
| **East Total Resources** | **8,578** | **8,433** | **8,452** | **8,479** | **8,504** | **9,348** | **9,542** | **9,927** | **9,863** | **9,788** |
| Load | 7,746 | 7,655 | 7,781 | 7,919 | 8,068 | 8,234 | 8,447 | 8,609 | 8,528 | 8,700 |
| Distributed Generation | (157) | (143) | (186) | (234) | (285) | (341) | (400) | (458) | (321) | (354) |
| Energy Efficiency | (91) | (141) | (206) | (274) | (349) | (428) | (520) | (631) | (696) | (801) |
| **East Total obligation** | **7,498** | **7,372** | **7,388** | **7,412** | **7,433** | **7,465** | **7,527** | **7,520** | **7,511** | **7,545** |
| **East Reserve Margin** | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 25.2% | 26.8% | 32.0% | 31.3% | 29.7% |
| **West** | | | | | | | | | | |
| Coal | 133 | 133 | 133 | 133 | 133 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 74 | 72 | 70 | 67 | 65 | 63 | 61 | 59 | 57 | 54 |
| Solar | 69 | 67 | 65 | 62 | 60 | 58 | 52 | 50 | 48 | 46 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 232 | 226 | 215 | 209 | 200 | 194 | 187 | 179 | 174 | 170 |
| Demand Response | 60 | 59 | 58 | 57 | 57 | 56 | 55 | 54 | 54 | 53 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 281 | 1,447 | 1,369 | 1,105 | 973 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **2,277** | **3,433** | **3,339** | **3,063** | **2,916** | **1,800** | **1,784** | **1,771** | **1,761** | **1,751** |
| Additional Proxy/Short-Term Purchases | 1,910 | 757 | 885 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 2 | 67 | 202 | 201 | 201 | 200 | 202 |
| Solar | 0 | 0 | 0 | 117 | 205 | 1,185 | 1,231 | 1,306 | 1,446 | 1,496 |
| Storage | 0 | 0 | 1 | 839 | 982 | 1,684 | 1,759 | 1,828 | 1,841 | 1,969 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **West Planned Resources** | **1,911** | **759** | **889** | **960** | **1,255** | **3,072** | **3,193** | **3,336** | **3,488** | **3,668** |
| **West Total Resources** | **4,189** | **4,192** | **4,227** | **4,022** | **4,171** | **4,872** | **4,977** | **5,107** | **5,249** | **5,419** |
| Load | 3,778 | 3,812 | 3,905 | 3,967 | 4,032 | 4,103 | 4,239 | 4,255 | 4,288 | 4,376 |
| Distributed Generation | (49) | (54) | (75) | (99) | (124) | (152) | (182) | (213) | (132) | (148) |
| Energy Efficiency | (67) | (94) | (135) | (178) | (220) | (263) | (318) | (359) | (389) | (431) |
| **West Total obligation** | **3,662** | **3,664** | **3,695** | **3,690** | **3,688** | **3,688** | **3,738** | **3,684** | **3,767** | **3,798** |
| **West Reserve Margin** | 14.4% | 14.4% | 14.4% | 9.0% | 13.1% | 32.1% | 33.1% | 38.6% | 39.4% | 42.7% |
| **System** | | | | | | | | | | |
| **Total Resources** | 12,767 | 12,625 | 12,680 | 12,501 | 12,675 | 14,220 | 14,518 | 15,034 | 15,113 | 15,207 |
| **Obligation** | 11,160 | 11,036 | 11,084 | 11,102 | 11,121 | 11,153 | 11,265 | 11,203 | 11,278 | 11,343 |
| **Planning Reserves (14.4%)** | 1,607 | 1,589 | 1,596 | 1,599 | 1,601 | 1,606 | 1,622 | 1,613 | 1,624 | 1,633 |
| **Obligation + Reserves** | 12,767 | 12,625 | 12,680 | 12,701 | 12,723 | 12,759 | 12,887 | 12,817 | 12,902 | 12,977 |
| **System Position** | 0 | 0 | 0 | (199) | (48) | 1,461 | 1,631 | 2,217 | 2,211 | 2,231 |
| **Reserve Margin** | **14.4%** | **14.4%** | **14.4%** | **12.6%** | **14.0%** | **27.5%** | **28.9%** | **34.2%** | **34.0%** | **34.1%** |

# Table 9.13 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,432 | 2,432 | 2,432 |
| Gas | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,469 | 3,322 | 3,322 | 3,322 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 437 | 421 | 404 | 387 | 371 | 355 | 308 | 293 | 278 | 263 | 249 |
| Solar | 392 | 381 | 340 | 329 | 319 | 308 | 297 | 286 | 276 | 243 | 233 |
| Other Renewable | 33 | 32 | 31 | 12 | 11 | 10 | 10 | 9 | 9 | 8 | 0 |
| Storage | 804 | 788 | 773 | 759 | 744 | 728 | 714 | 699 | 684 | 668 | 654 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 291 | 269 | 221 | 212 | 203 | 192 | 184 | 176 | 169 | 162 | 155 |
| Demand Response | 422 | 401 | 402 | 398 | 400 | 406 | 398 | 375 | 376 | 389 | 351 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **8,851** | **8,763** | **8,643** | **8,569** | **8,519** | **8,472** | **8,383** | **8,310** | **7,622** | **7,564** | **7,472** |
| Additional Proxy/Short-Term Purchas | 0 | 0 | 0 | 0 | 0 | 0 | 64 | 0 | 672 | 628 | 475 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Wind | 115 | 112 | 110 | 108 | 106 | 104 | 101 | 99 | 97 | 95 | 92 |
| Solar | 135 | 131 | 127 | 123 | 120 | 116 | 111 | 107 | 104 | 100 | 96 |
| Storage | 26 | 25 | 25 | 25 | 24 | 24 | 23 | 592 | 581 | 858 | 1,289 |
| Nuclear | 450 | 447 | 445 | 442 | 440 | 437 | 435 | 432 | 430 | 427 | 426 |
| Demand Response | 141 | 138 | 197 | 193 | 189 | 186 | 209 | 253 | 257 | 264 | 270 |
| **East Planned Resources** | **868** | **856** | **907** | **895** | **882** | **869** | **947** | **1,487** | **2,144** | **2,373** | **2,650** |
| **East Total Resources** | **9,719** | **9,620** | **9,550** | **9,464** | **9,401** | **9,340** | **9,330** | **9,797** | **9,766** | **9,937** | **10,123** |
| Load | 8,893 | 9,150 | 9,349 | 9,567 | 9,774 | 9,993 | 10,214 | 10,478 | 10,693 | 10,891 | 11,097 |
| Distributed Generation | (385) | (415) | (445) | (474) | (503) | (529) | (557) | (584) | (609) | (635) | (660) |
| Energy Efficiency | (911) | (983) | (1,112) | (1,227) | (1,325) | (1,407) | (1,501) | (1,482) | (1,547) | (1,570) | (1,588) |
| **East Total obligation** | **7,596** | **7,752** | **7,792** | **7,865** | **7,946** | **8,057** | **8,156** | **8,413** | **8,536** | **8,686** | **8,848** |
| **East Reserve Margin** | 27.9% | 24.1% | 22.6% | 20.3% | 18.3% | 15.9% | 14.4% | 16.5% | 14.4% | 14.4% | 14.4% |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 52 | 50 | 48 | 46 | 44 | 41 | 39 | 37 | 35 | 33 | 31 |
| Solar | 45 | 43 | 41 | 39 | 37 | 35 | 13 | 12 | 11 | 11 | 10 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 165 | 160 | 142 | 138 | 132 | 128 | 124 | 120 | 101 | 97 | 95 |
| Demand Response | 52 | 51 | 51 | 50 | 49 | 48 | 48 | 47 | 46 | 45 | 44 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **1,741** | **1,731** | **1,708** | **1,700** | **1,689** | **1,681** | **1,651** | **1,644** | **1,621** | **1,613** | **1,608** |
| Additional Proxy/Short-Term Purchas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 238 | 241 | 259 | 262 | 261 | 299 | 303 | 302 | 303 | 302 | 310 |
| Solar | 1,455 | 1,446 | 1,383 | 1,431 | 1,553 | 1,510 | 1,470 | 1,387 | 1,307 | 1,314 | 1,255 |
| Storage | 1,966 | 1,980 | 1,971 | 2,144 | 2,200 | 3,176 | 3,299 | 3,487 | 3,863 | 4,035 | 4,365 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 8 |
| **West Planned Resources** | **3,660** | **3,670** | **3,616** | **3,840** | **4,016** | **4,988** | **5,075** | **5,179** | **5,476** | **5,654** | **5,938** |
| **West Total Resources** | **5,401** | **5,401** | **5,325** | **5,540** | **5,705** | **6,668** | **6,727** | **6,823** | **7,097** | **7,267** | **7,545** |
| Load | 4,475 | 4,577 | 4,692 | 4,807 | 4,927 | 5,049 | 5,173 | 5,376 | 5,430 | 5,553 | 5,680 |
| Distributed Generation | (163) | (177) | (192) | (206) | (221) | (234) | (249) | (263) | (277) | (290) | (304) |
| Energy Efficiency | (471) | (515) | (571) | (603) | (634) | (661) | (691) | (774) | (591) | (599) | (612) |
| **West Total obligation** | **3,841** | **3,885** | **3,929** | **3,998** | **4,073** | **4,154** | **4,233** | **4,340** | **4,562** | **4,663** | **4,764** |
| **West Reserve Margin** | 40.6% | 39.0% | 35.5% | 38.6% | 40.1% | 60.5% | 58.9% | 57.2% | 55.6% | 55.9% | 58.4% |
| **System** | | | | | | | | | | | |
| **Total Resources** | 15,120 | 15,021 | 14,875 | 15,003 | 15,106 | 16,009 | 16,057 | 16,620 | 16,863 | 17,205 | 17,668 |
| **Obligation** | 11,438 | 11,637 | 11,721 | 11,863 | 12,019 | 12,211 | 12,388 | 12,753 | 13,099 | 13,349 | 13,612 |
| **Planning Reserves (14.4%)** | 1,647 | 1,676 | 1,688 | 1,708 | 1,731 | 1,758 | 1,784 | 1,836 | 1,886 | 1,922 | 1,960 |
| **Obligation + Reserves** | 13,085 | 13,313 | 13,409 | 13,572 | 13,750 | 13,969 | 14,172 | 14,589 | 14,985 | 15,272 | 15,573 |
| **System Position** | 2,036 | 1,709 | 1,465 | 1,432 | 1,357 | 2,040 | 1,885 | 2,031 | 1,878 | 1,933 | 2,095 |
| **Reserve Margin** | **32.2%** | **29.1%** | **26.9%** | **26.5%** | **25.7%** | **31.1%** | **29.6%** | **30.3%** | **28.7%** | **28.9%** | **29.8%** |

# Table 9.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 4,147 | 3,734 | 3,734 | 3,499 | 3,185 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 |
| Gas | 3,003 | 3,334 | 3,334 | 3,335 | 3,526 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 1,837 | 1,957 | 1,892 | 1,829 | 1,766 | 1,657 | 1,523 | 1,463 | 1,404 | 1,346 |
| Solar | 38 | 104 | 101 | 98 | 95 | 92 | 89 | 85 | 82 | 79 |
| Other Renewable | 41 | 39 | 38 | 37 | 35 | 34 | 33 | 32 | 30 | 29 |
| Storage | 1 | 621 | 606 | 591 | 576 | 561 | 546 | 531 | 516 | 500 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 186 | 181 | 176 | 171 | 166 | 161 | 156 | 149 | 140 | 124 |
| Demand Response | 119 | 118 | 118 | 128 | 129 | 128 | 121 | 120 | 128 | 127 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (1,600) | (1,600) | (1,600) | (1,226) | (930) | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **7,804** | **8,523** | **8,433** | **8,495** | **8,581** | **9,208** | **9,042** | **8,954** | **8,875** | **8,780** |
| Additional Proxy/Short-Term Purchases | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 |
| Wind | 0 | 0 | 0 | 0 | 90 | 175 | 316 | 306 | 297 | 287 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 39 | 37 | 36 | 35 |
| Storage | 0 | 0 | 1 | 1 | 17 | 18 | 18 | 18 | 18 | 17 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 403 | 401 | 398 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Planned Resources** | **0** | **0** | **2** | **2** | **109** | **196** | **374** | **767** | **754** | **740** |
| **East Total Resources** | **7,804** | **8,523** | **8,435** | **8,496** | **8,689** | **9,404** | **9,417** | **9,722** | **9,629** | **9,520** |
| Load | 5,898 | 5,911 | 6,036 | 6,164 | 6,278 | 6,408 | 6,569 | 6,706 | 6,899 | 7,084 |
| Distributed Generation | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| Energy Efficiency | (75) | (118) | (157) | (197) | (239) | (283) | (331) | (388) | (450) | (513) |
| **East Total obligation** | **5,821** | **5,790** | **5,876** | **5,963** | **6,033** | **6,119** | **6,231** | **6,309** | **6,440** | **6,560** |
| **East Reserve Margin** | 34.1% | 47.2% | 43.5% | 42.5% | 44.0% | 53.7% | 51.1% | 54.1% | 49.5% | 45.1% |
| **West** | | | | | | | | | | |
| Coal | 147 | 147 | 147 | 147 | 147 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 64 | 62 | 59 | 57 | 55 | 53 | 51 | 49 | 47 | 45 |
| Solar | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 70 | 69 | 62 | 61 | 58 | 57 | 57 | 56 | 56 | 56 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 1,600 | 1,600 | 1,600 | 1,226 | 930 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **3,345** | **3,342** | **3,333** | **2,956** | **2,655** | **1,574** | **1,571** | **1,568** | **1,566** | **1,561** |
| Additional Proxy/Short-Term Purchases | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 2 | 67 | 201 | 201 | 200 | 199 | 202 |
| Solar | 0 | 0 | 0 | 30 | 52 | 299 | 309 | 326 | 359 | 368 |
| Storage | 0 | 0 | 1 | 1,091 | 1,276 | 2,037 | 2,104 | 2,193 | 2,206 | 2,369 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 41 | 51 | 56 | 55 | 58 | 58 | 59 |
| **West Planned Resources** | **0** | **0** | **2** | **1,164** | **1,446** | **2,594** | **2,669** | **2,776** | **2,821** | **2,997** |
| **West Total Resources** | **3,345** | **3,342** | **3,335** | **4,120** | **4,101** | **4,168** | **4,240** | **4,344** | **4,387** | **4,559** |
| Load | 3,511 | 3,571 | 3,640 | 3,701 | 3,741 | 3,805 | 3,904 | 3,981 | 4,068 | 4,160 |
| Distributed Generation | (0) | (0) | (1) | (1) | (1) | (1) | (1) | (2) | (2) | (2) |
| Energy Efficiency | (52) | (65) | (118) | (173) | (229) | (286) | (345) | (401) | (457) | (511) |
| **West Total obligation** | **3,459** | **3,506** | **3,521** | **3,527** | **3,511** | **3,517** | **3,558** | **3,578** | **3,609** | **3,647** |
| **West Reserve Margin** | -3.3% | -4.7% | -5.3% | 16.8% | 16.8% | 18.5% | 19.2% | 21.4% | 21.5% | 25.0% |
| **System** | | | | | | | | | | |
| **Total Resources** | 11,149 | 11,865 | 11,769 | 12,616 | 12,790 | 13,572 | 13,657 | 14,066 | 14,016 | 14,079 |
| **Obligation** | 9,281 | 9,296 | 9,397 | 9,490 | 9,544 | 9,636 | 9,789 | 9,888 | 10,049 | 10,207 |
| **Planning Reserves (16.8%)** | 1,559 | 1,562 | 1,579 | 1,594 | 1,603 | 1,619 | 1,645 | 1,661 | 1,688 | 1,715 |
| **Obligation + Reserves** | 10,840 | 10,858 | 10,975 | 11,084 | 11,147 | 11,255 | 11,434 | 11,549 | 11,738 | 11,922 |
| **System Position** | 309 | 1,008 | 794 | 1,532 | 1,643 | 2,317 | 2,223 | 2,517 | 2,278 | 2,157 |
| **Reserve Margin** | **20.1%** | **27.6%** | **25.2%** | **32.9%** | **34.0%** | **40.8%** | **39.5%** | **42.3%** | **39.5%** | **37.9%** |

# Table 9.15 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 2,503 | 2,503 | 2,503 |
| Gas | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,378 | 3,378 | 3,378 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 1,285 | 1,226 | 1,168 | 1,107 | 1,049 | 990 | 850 | 797 | 744 | 689 | 636 |
| Solar | 76 | 73 | 70 | 67 | 64 | 61 | 58 | 55 | 52 | 42 | 39 |
| Other Renewable | 28 | 26 | 25 | 9 | 8 | 8 | 7 | 7 | 6 | 6 | 0 |
| Storage | 485 | 470 | 455 | 440 | 425 | 410 | 395 | 379 | 365 | 350 | 334 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 120 | 112 | 99 | 94 | 90 | 86 | 82 | 78 | 75 | 71 | 67 |
| Demand Response | 128 | 117 | 121 | 121 | 125 | 132 | 129 | 117 | 121 | 132 | 109 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Existing Resources** | **8,697** | **8,600** | **8,511** | **8,412** | **8,336** | **8,262** | **8,096** | **8,008** | **7,276** | **7,204** | **7,101** |
| Additional Proxy/Short-Term Purchas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Wind | 278 | 268 | 259 | 250 | 240 | 231 | 221 | 212 | 202 | 193 | 183 |
| Solar | 33 | 32 | 31 | 30 | 28 | 27 | 26 | 25 | 23 | 22 | 21 |
| Storage | 17 | 16 | 16 | 16 | 15 | 15 | 14 | 370 | 360 | 499 | 711 |
| Nuclear | 396 | 394 | 392 | 389 | 387 | 384 | 381 | 379 | 377 | 374 | 372 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| **East Planned Resources** | **727** | **713** | **700** | **687** | **673** | **660** | **645** | **988** | **965** | **1,091** | **1,291** |
| **East Total Resources** | **9,423** | **9,313** | **9,212** | **9,099** | **9,009** | **8,921** | **8,742** | **8,996** | **8,241** | **8,294** | **8,392** |
| Load | 7,248 | 7,421 | 7,645 | 7,863 | 8,087 | 8,287 | 8,466 | 8,705 | 8,909 | 9,134 | 9,224 |
| Distributed Generation | (11) | (11) | (12) | (13) | (13) | (14) | (14) | (14) | (15) | (15) | (16) |
| Energy Efficiency | (579) | (624) | (700) | (766) | (826) | (886) | (954) | (973) | (1,022) | (1,049) | (1,077) |
| **East Total obligation** | **6,659** | **6,786** | **6,932** | **7,084** | **7,248** | **7,387** | **7,498** | **7,717** | **7,872** | **8,070** | **8,131** |
| **East Reserve Margin** | 41.5% | 37.2% | 32.9% | 28.4% | 24.3% | 20.8% | 16.6% | 16.6% | 4.7% | 2.8% | 3.2% |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 42 | 40 | 38 | 36 | 34 | 32 | 30 | 28 | 25 | 23 | 21 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 55 | 54 | 53 | 53 | 51 | 51 | 50 | 50 | 50 | 49 | 49 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West Existing Resources** | **1,559** | **1,555** | **1,552** | **1,550** | **1,546** | **1,544** | **1,541** | **1,539** | **1,536** | **1,534** | **1,531** |
| Additional Proxy/Short-Term Purchas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 237 | 241 | 258 | 261 | 260 | 298 | 301 | 300 | 301 | 300 | 308 |
| Solar | 355 | 349 | 331 | 339 | 363 | 348 | 333 | 309 | 286 | 280 | 260 |
| Storage | 2,362 | 2,379 | 2,362 | 2,558 | 2,619 | 3,606 | 3,732 | 3,910 | 4,279 | 4,439 | 4,761 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 60 | 67 | 66 | 73 | 75 | 82 | 83 | 82 | 85 | 84 | 87 |
| **West Planned Resources** | **3,013** | **3,036** | **3,018** | **3,231** | **3,317** | **4,334** | **4,450** | **4,601** | **4,951** | **5,103** | **5,417** |
| **West Total Resources** | **4,572** | **4,591** | **4,570** | **4,781** | **4,863** | **5,878** | **5,991** | **6,140** | **6,488** | **6,636** | **6,948** |
| Load | 4,232 | 4,334 | 4,471 | 4,605 | 4,720 | 4,832 | 4,959 | 5,143 | 5,253 | 5,374 | 5,365 |
| Distributed Generation | (2) | (3) | (3) | (3) | (3) | (3) | (3) | (4) | (4) | (4) | (4) |
| Energy Efficiency | (568) | (624) | (668) | (714) | (760) | (819) | (858) | (900) | (786) | (803) | (826) |
| **West Total obligation** | **3,662** | **3,707** | **3,800** | **3,888** | **3,957** | **4,010** | **4,097** | **4,239** | **4,463** | **4,567** | **4,535** |
| **West Reserve Margin** | 24.9% | 23.9% | 20.3% | 23.0% | 22.9% | 46.6% | 46.2% | 44.8% | 45.4% | 45.3% | 53.2% |
| **System** | | | | | | | | | | | |
| **Total Resources** | 13,995 | 13,904 | 13,782 | 13,880 | 13,872 | 14,799 | 14,732 | 15,136 | 14,729 | 14,930 | 15,340 |
| **Obligation** | 10,321 | 10,493 | 10,732 | 10,973 | 11,205 | 11,398 | 11,596 | 11,957 | 12,334 | 12,637 | 12,666 |
| **Planning Reserves (16.8%)** | 1,486 | 1,511 | 1,545 | 1,580 | 1,614 | 1,641 | 1,670 | 1,722 | 1,776 | 1,820 | 1,824 |
| **Obligation + Reserves** | 11,807 | 12,003 | 12,278 | 12,553 | 12,819 | 13,039 | 13,265 | 13,678 | 14,110 | 14,456 | 14,490 |
| **System Position** | 2,188 | 1,901 | 1,505 | 1,327 | 1,053 | 1,760 | 1,467 | 1,458 | 618 | 474 | 850 |
| **Reserve Margin** | **35.6%** | **32.5%** | **28.4%** | **26.5%** | **23.8%** | **29.8%** | **27.1%** | **26.6%** | **19.4%** | **18.1%** | **21.1%** |

## Integrated Portfolio Resource Comparisons by Technology and Year

Table 9.16 through Table 9.28 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 9.29 through Table 9.32 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology. Table 9.33 summarizes how full jurisdictional studies were identified for each variant and price-policy scenario. Full jurisdictional studies are only modified and endogenously developed to the extent the variant relates to resources that can be selected for that jurisdiction. As a result, the Oregon and Washington full jurisdictional portfolios are not modified in the variants that examine coal resource alternatives. Similarly, Washington requires planning under the social cost of greenhouse gases, so its full jurisdictional portfolio is not modified under other price-policy scenarios. Those variants related to clean resources in which all jurisdictions can participate have full jurisdictional portfolios for each jurisdiction.

**Table 9.16 – New Gas[1]**

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 99 | - | - | - | 99 |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 496 | 496 |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.17 - Nuclear[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MR Base | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MN - No CCS | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MN - Offshore Wind | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| MN - Hunter Retire | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| LN Base | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| HH Base | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| SC Base | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.18 – Renewable Peaking[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.19 – DSM – Energy Efficiency

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | 92 | 89 | 209 | 220 | 239 | 261 | 329 | 291 | 299 | 295 | 299 | 315 | 347 | 314 | 293 | 301 | 303 | 315 | 238 | 205 | 182 | 5,436 |
| MR Base | 92 | 89 | 209 | 221 | 231 | 256 | 329 | 313 | 326 | 315 | 318 | 326 | 369 | 335 | 313 | 308 | 304 | 315 | 254 | 224 | 209 | 5,656 |
| MN - No CCS | 92 | 89 | 207 | 218 | 229 | 253 | 326 | 287 | 284 | 282 | 294 | 300 | 333 | 312 | 292 | 289 | 304 | 315 | 260 | 232 | 219 | 5,417 |
| MN - No Nuclear | 92 | 89 | 210 | 220 | 237 | 256 | 331 | 314 | 310 | 299 | 299 | 314 | 324 | 267 | 283 | 251 | 286 | 299 | 282 | 261 | 220 | 5,444 |
| MN - No Coal 2032 | 92 | 89 | 210 | 221 | 231 | 251 | 319 | 304 | 308 | 298 | 309 | 325 | 347 | 314 | 293 | 299 | 304 | 315 | 270 | 246 | 220 | 5,565 |
| MN - Offshore Wind | 92 | 89 | 209 | 219 | 240 | 260 | 331 | 292 | 306 | 294 | 299 | 322 | 345 | 314 | 310 | 301 | 303 | 314 | 222 | 218 | 182 | 5,462 |
| MN - No Forward Technology | 92 | 89 | 210 | 220 | 237 | 256 | 331 | 315 | 310 | 301 | 301 | 315 | 324 | 267 | 283 | 251 | 286 | 299 | 282 | 247 | 219 | 5,435 |
| MN - Geothermal | 92 | 89 | 207 | 217 | 227 | 245 | 306 | 298 | 303 | 293 | 313 | 320 | 354 | 335 | 313 | 308 | 305 | 314 | 270 | 259 | 218 | 5,586 |
| MN - Hunter Retire | 92 | 89 | 219 | 232 | 243 | 265 | 332 | 306 | 310 | 307 | 312 | 328 | 358 | 326 | 306 | 301 | 304 | 315 | 258 | 224 | 209 | 5,636 |
| LN Base | 92 | 89 | 207 | 223 | 236 | 257 | 325 | 288 | 300 | 289 | 311 | 318 | 343 | 309 | 322 | 305 | 302 | 291 | 272 | 244 | 217 | 5,540 |
| HH Base | 92 | 89 | 211 | 223 | 237 | 257 | 309 | 295 | 300 | 289 | 309 | 315 | 347 | 326 | 305 | 302 | 305 | 316 | 259 | 252 | 230 | 5,568 |
| SC Base | 92 | 89 | 211 | 226 | 241 | 263 | 329 | 293 | 314 | 305 | 318 | 325 | 357 | 325 | 320 | 308 | 305 | 315 | 270 | 260 | 219 | 5,685 |

## Table 9.20 – DSM – Demand Response

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | 18 | 2 | - | 63 | 21 | 120 | 99 | 5 | 1 | 3 | 3 | 21 | 112 | 18 | 5 | 24 | 61 | 106 | 29 | 26 | 52 | 789 |
| MR Base | 18 | 2 | - | 63 | 19 | 16 | 3 | 5 | 1 | 5 | 3 | 19 | 323 | 18 | 5 | 24 | 114 | 34 | 34 | 25 | 205 | 936 |
| MN - No CCS | 18 | 2 | - | 63 | 19 | 34 | 187 | 5 | 1 | 3 | 3 | 21 | 93 | 18 | 5 | 25 | 6 | 176 | 30 | 26 | 50 | 785 |
| MN - No Nuclear | 18 | 2 | - | 63 | 20 | 136 | 13 | 8 | 26 | 79 | 32 | 4 | 70 | 14 | 151 | 24 | 46 | 31 | 12 | 102 | 48 | 899 |
| MN - No Coal 2032 | 18 | 2 | - | 63 | 19 | 16 | - | 5 | 1 | 3 | 3 | 19 | 328 | 18 | 5 | 25 | 5 | 146 | 33 | 27 | 51 | 787 |
| MN - Offshore Wind | 18 | 2 | - | 63 | 20 | 206 | 21 | 8 | - | 10 | 4 | 4 | 110 | 29 | 5 | 11 | 8 | 166 | 30 | 31 | 50 | 796 |
| MN - No Forward Technology | 18 | 2 | - | 63 | 21 | 131 | 13 | 10 | 26 | 77 | 35 | 6 | 70 | 13 | 151 | 24 | 45 | 31 | 12 | 102 | 57 | 907 |
| MN - Geothermal | 18 | 2 | - | 60 | 20 | 16 | - | 8 | - | 7 | 5 | 7 | - | 13 | 10 | 26 | 450 | 29 | 8 | 7 | 103 | 789 |
| MN - Hunter Retire | 18 | 2 | - | 63 | 19 | 211 | 14 | 5 | 1 | 3 | 3 | 23 | 113 | 18 | 129 | 25 | 7 | 147 | 29 | 30 | 87 | 947 |
| LN Base | 18 | 2 | - | 63 | 19 | 75 | 149 | 7 | 2 | 4 | 4 | 14 | 110 | 14 | 5 | 24 | 124 | - | 8 | 80 | 51 | 773 |
| HH Base | 18 | 2 | - | 63 | 22 | 13 | - | 5 | 1 | 3 | 3 | 19 | - | 18 | 8 | 24 | 5 | 463 | 15 | 157 | 30 | 869 |
| SC Base | 18 | 2 | 2 | 64 | 28 | 191 | 14 | 5 | 1 | 1 | 18 | 11 | 108 | 18 | 10 | 24 | 6 | 150 | 12 | 50 | 46 | 779 |

## Table 9.21 – Utility Scale Wind[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | 21 | 794 | 1,452 | 344 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 3,782 |
| MR Base | - | - | - | 21 | 694 | 1,931 | 200 | 382 | 100 | 129 | 447 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,698 |
| MN - No CCS | - | - | - | 21 | 594 | 1,252 | 276 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 3,314 |
| MN - No Nuclear | - | - | - | - | 500 | 1,728 | 300 | 301 | 302 | 322 | 380 | 292 | 2 | - | - | - | - | - | - | - | - | 4,127 |
| MN - No Coal 2032 | - | - | - | 21 | 594 | 2,914 | - | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,700 |
| MN - Offshore Wind | - | - | 100 | 100 | 762 | 630 | 400 | 1 | 1,000 | 98 | 100 | 100 | - | - | - | 353 | 95 | - | - | - | 162 | 3,901 |
| MN - No Forward Technology | - | - | - | - | 694 | 1,482 | 302 | 301 | - | 22 | 294 | 53 | 176 | 38 | - | 367 | 91 | - | 1 | - | 147 | 3,968 |
| MN - Geothermal | - | - | - | - | 594 | 402 | 200 | 1 | 2 | - | 169 | 204 | 185 | 89 | - | 360 | 62 | - | 38 | - | 19 | 2,325 |
| MN - Hunter Retire | - | - | - | 21 | 894 | 1,842 | 340 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,268 |
| LN Base | - | - | - | - | 594 | 1,265 | 594 | 2 | - | 24 | 369 | 1 | 176 | 38 | - | 365 | 90 | - | 3 | - | 150 | 3,671 |
| HH Base | - | - | - | 21 | 1,214 | 2,677 | - | 2 | - | 29 | 349 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 5,086 |
| SC Base | - | - | - | 20 | 1,614 | 1,353 | 352 | 1 | - | 65 | 293 | 237 | 114 | 26 | 29 | 423 | 47 | - | - | 11 | 196 | 4,781 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.22 – Small Scale Wind[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.23 – Utility Solar[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | 222 | 180 | 1,690 | 849 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 4,765 |
| MR Base | - | - | - | 222 | 180 | 1,690 | 863 | 934 | 420 | 467 | 213 | 133 | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 6,065 |
| MN - No CCS | - | - | - | 222 | 180 | 1,690 | 614 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 4,530 |
| MN - No Nuclear | - | - | - | 656 | - | 1,444 | 962 | 299 | 326 | 395 | 456 | 391 | 1 | - | - | - | - | - | - | 22 | 108 | 5,060 |
| MN - No Coal 2032 | - | - | - | 222 | 180 | 1,690 | 494 | 635 | 545 | 792 | 114 | 100 | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 5,715 |
| MN - Offshore Wind | - | - | 103 | 237 | 205 | 1,382 | 885 | 249 | 104 | 100 | 100 | 100 | 103 | 392 | 444 | 100 | - | - | - | 116 | 26 | 4,646 |
| MN - No Forward Technology | - | - | 119 | 13 | - | 1,968 | 962 | 220 | 327 | 316 | 49 | - | 1 | - | 577 | 85 | 34 | - | - | 239 | 111 | 5,021 |
| MN - Geothermal | - | - | 29 | 505 | 1 | 1,168 | 200 | 163 | 349 | 199 | 103 | - | 2 | 27 | 82 | 229 | 211 | - | - | 333 | 104 | 3,705 |
| MN - Hunter Retire | - | - | - | 222 | 180 | 2,352 | 1,173 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 5,751 |
| LN Base | - | - | - | 200 | 138 | 1,761 | 517 | 239 | 398 | 230 | 7 | - | 1 | - | 570 | 93 | 61 | - | - | 44 | 110 | 4,369 |
| HH Base | - | - | - | 222 | 181 | 1,813 | 1,904 | 734 | 603 | 360 | 196 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 6,956 |
| SC Base | - | - | 22 | 381 | 144 | 2,005 | 1,259 | 335 | 400 | 206 | 225 | 90 | 1 | - | 471 | 115 | - | - | - | 288 | 92 | 6,034 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.24 – Small Scale Solar[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| MR Base | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| MN - No CCS | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| MN - No Nuclear | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 26 | 53 | - | 307 | - | 49 | 153 | - | 10 | 126 | 36 | 1,147 |
| MN - No Coal 2032 | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| MN - Offshore Wind | - | - | - | - | - | 416 | - | - | - | - | - | - | - | 24 | 29 | 114 | 142 | - | 36 | 250 | 26 | 1,037 |
| MN - No Forward Technology | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 127 | - | 307 | - | - | 117 | - | 35 | 108 | 36 | 1,147 |
| MN - Geothermal | - | - | - | - | - | 304 | - | 11 | 29 | 17 | 23 | 17 | 15 | 201 | 331 | 13 | 21 | - | 35 | 18 | 26 | 1,061 |
| MN - Hunter Retire | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| LN Base | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 31 | 153 | - | 306 | - | - | 97 | - | 35 | 101 | 36 | 1,146 |
| HH Base | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| SC Base | - | - | - | - | - | 320 | 2 | 19 | 26 | 23 | 24 | 20 | 9 | 312 | - | 42 | 170 | - | - | 56 | 26 | 1,049 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.25 – Geothermal

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | 403 | 304 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 707 |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.26 – Battery, < 8 hour [1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | 1,146 | 242 | 296 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | 713 | 5 | 459 | 733 | 4,451 |
| MR Base | - | - | - | 1,156 | 215 | 438 | - | 119 | 39 | 210 | 20 | 47 | 27 | 175 | 67 | 113 | 582 | 33 | 5 | 305 | 324 | 3,875 |
| MN - No CCS | - | - | 2 | 1,146 | 215 | 299 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 188 | 113 | 67 | 115 | 5 | 758 | - | 3,518 |
| MN - No Nuclear | - | - | 16 | 1,399 | 109 | 462 | - | 274 | 39 | 209 | 34 | 72 | 313 | 130 | 6 | 937 | 159 | - | 605 | 10 | 602 | 5,376 |
| MN - No Coal 2032 | - | - | - | 1,145 | 215 | 565 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | 152 | 5 | 416 | 18 | 3,373 |
| MN - Offshore Wind | - | - | 7 | 2,291 | 527 | 528 | - | 149 | - | 131 | 46 | 54 | 2 | 251 | 113 | 1,454 | 211 | 675 | 768 | 82 | 834 | 8,123 |
| MN - No Forward Technology | - | - | - | 1,349 | 179 | 316 | 6 | 182 | 41 | 279 | 30 | 83 | 333 | 186 | 112 | 1,322 | 272 | 287 | 444 | 251 | 605 | 6,277 |
| MN - Geothermal | - | - | - | 1,048 | 184 | 650 | - | 241 | 4 | 203 | 37 | 70 | - | 179 | 37 | 1,437 | 473 | - | 104 | 53 | 449 | 5,169 |
| MN - Hunter Retire | - | - | 4 | 1,145 | 215 | 836 | - | 119 | 39 | 210 | 20 | 47 | 41 | 175 | 67 | 113 | 67 | 129 | 5 | 109 | 185 | 3,526 |
| LN Base | - | - | - | 1,252 | 220 | 609 | - | 99 | 39 | 209 | 23 | 82 | - | 239 | 67 | 1,126 | 1,060 | - | 272 | 12 | 1,437 | 6,746 |
| HH Base | - | - | 2 | 1,146 | 302 | 1,383 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | - | 5 | - | - | 3,695 |
| SC Base | - | - | - | 2,147 | 329 | 484 | - | 175 | 7 | 194 | 2 | 23 | - | 286 | 121 | 1,095 | 138 | 245 | 192 | 237 | 531 | 6,206 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.27 – Battery, 8-23 hour[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.28 – Battery, 24+ hour [1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 319 | 402 | 197 | 358 | 3,073 |
| MR Base | - | - | - | - | - | 510 | 91 | 3 | 4 | 3 | 4 | 4 | 175 | 83 | 37 | 939 | 107 | 510 | 401 | 197 | 455 | 3,523 |
| MN - No CCS | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 261 | 402 | 197 | 358 | 3,015 |
| MN - No Nuclear | - | - | - | - | - | 191 | 2 | 3 | 3 | 3 | 3 | 3 | 114 | 3 | 3 | 186 | 78 | 233 | 168 | 118 | 4 | 1,115 |
| MN - No Coal 2032 | - | - | - | - | - | 510 | 91 | 3 | 4 | 3 | 4 | 4 | 33 | 83 | 37 | 939 | 107 | 390 | 401 | 197 | 358 | 3,164 |
| MN - Offshore Wind | - | - | - | - | - | 1,577 | 20 | 23 | 23 | 22 | 25 | 26 | 24 | 27 | 28 | 127 | 34 | 142 | 96 | 30 | 34 | 2,258 |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | 85 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 13 | 84 | 85 | 316 | 174 | 88 | 855 |
| MN - Hunter Retire | - | - | - | - | - | 837 | 91 | 3 | 4 | 3 | 4 | 4 | 123 | 83 | 146 | 939 | 107 | 455 | 401 | 197 | 537 | 3,934 |
| LN Base | - | - | - | - | - | 271 | 95 | 4 | 4 | 3 | 4 | 4 | 17 | 38 | 40 | 132 | 26 | 215 | 137 | 159 | 16 | 1,165 |
| HH Base | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 641 | 402 | 197 | 598 | 3,635 |
| SC Base | - | - | - | - | - | 1,410 | 107 | 19 | 19 | 18 | 20 | 21 | 69 | 22 | 34 | 141 | 141 | 442 | 219 | 169 | 94 | 2,945 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 9.29 – Majority Owned Coal Retirements[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MR Base | - | - | - | (220) | - | - | - | (686) | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| MN - No CCS | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MN - No Nuclear | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MN - No Coal 2032 | - | - | - | (220) | - | - | - | (686) | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| MN - Offshore Wind | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MN - No Forward Technology | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MN - Geothermal | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| MN - Hunter Retire | - | - | - | (220) | - | (1,158) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,378) |
| LN Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| HH Base | - | - | - | (220) | - | - | (268) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (488) |
| SC Base | - | - | - | (488) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (269) | - | - | (757) |

[1] Negative values indicate retirement of coal capacity.

## Table 9.30 – Carbon Capture and Sequestration Selections

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| MR Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| MN - No Forward Technology | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| MN - Geothermal | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | - | 0 |
| MN - Hunter Retire | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| LN Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | - | 0 |
| HH Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| SC Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |

## Table 9.31 – Coal to Gas Conversion Selections

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 406 |
| MR Base | - | 357 | - | - | 205 | 1,979 | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 2,385 |
| MN - No CCS | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | (403) | - | - | 159 |
| MN - No Nuclear | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| MN - No Coal 2032 | - | 357 | - | - | 205 | 2,679 | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 3,085 |
| MN - Offshore Wind | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 406 |
| MN - No Forward Technology | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| MN - Geothermal | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| MN - Hunter Retire | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| LN Base | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| HH Base | - | 357 | - | - | 205 | 599 | - | - | (269) | - | - | - | - | - | - | - | - | - | - | - | - | 892 |
| SC Base | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | (99) | - | - | 793 |

## Table 9.32 – Gas Retirements[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Forward Technology | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Hunter Retire | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | (167) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (167) |

[1]Only reports retirements of existing gas plants.

## Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 7 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. Consequently, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS. As discussed in Chapter 8, some of the studies below were able to fulfill the requirements of another study and are noted as such. Table 9.33 summarizes the jurisdictional studies which were integrated for each of the variants and price-policy scenarios. Variants evaluating technology that is available in all jurisdictions have jurisdictional portfolios developed for each jurisdiction. Where a jurisdiction does not use the applicable technology or assumptions under consideration in the variant, selections for that jurisdiction are held constant at their base scenario. For example, neither Oregon nor Washington participates in coal-fired resources over the long term, so studies that evaluate alternative decisions for coal-fired resources hold Oregon and Washington jurisdictional results constant. Similarly, Washington requires that the SCGHG price-policy scenario be used for planning, so Washington selections under SCGHG are integrated regardless of the price-policy scenario under consideration.

**Table 9.33 – Jurisdictional Studies for Variants and Price-Policy Scenarios**

| Price-policy / Variant | UIWC | OR | WA | Description |
|---|---|---|---|---|
| MN - Base | Base | Base | | MN price-policy scenario |
| MR - Base | ✓ | | | MR price-policy scenario |
| LN - Base | ✓ | ✓ | | LN price-policy scenario |
| HH - Base | ✓ | ✓ | | HH price-policy scenario |
| SC - Base | ✓ | ✓ | Base | SCGHG price-policy scenario |
| MN - No CCS | ✓ | | | No coal units are able to select CCS technology |
| MN - No Coal 2032 | ✓ | | | All coal must retire or convert by January 1, 2032 |
| MN - Hunter Retire | ✓ | | | Require all Hunter units to retire no later than 1/1/2030 |
| MN - No Nuclear | ✓ | ✓ | ✓ (SC) | No nuclear resources are eligible for selection |
| MN - Offshore Wind | ✓ | ✓ | ✓ (SC) | Counterfactual to preferred portfolio selection |
| MN - No Forward Technology | ✓ | ✓ | ✓ (SC) | No nuclear, hydrogen or 100-hour storage, or biodiesel peaking |
| MN - Geothermal | ✓ | ✓ | ✓ (SC) | Counterfactual to preferred portfolio selection |
| MN - All Coal End of Life | Same as No CCS | | | Continue 2025 coal technology |
| MN - No New Gas | Same as Preferred Portfolio | | | No new gas resources allowed |
| MN - Force All Gas Conversions | Same as No Coal 2032 | | | All coal must be converted to natural gas where available |

Table 9.34 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no $CO_2$) price-policy scenario. As in previous IRPs, model results can indicate the need to examine costs and risks beyond the model horizon. End effects were applied to all portfolios run under the MN price-policy for a 5-year period after the study horizon, results of which can be seen in this table. The specific trends that led to this examination can be found in the discussion of individual cases below.

**Table 9.34 – Integrated Portfolios Under Medium Gas/ Zero $CO_2$**

| | ST Value | | | Risk Adjusted | | | With End Effects | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case - MN | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Stochastic PVRR | Change from Lowest Cost Portfolio ($m) | Rank | PVRR ($m) | Change from Lowest Portfolio | Rank | Total CO2 Emissions, 2025-2045 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base MN | 27,233 | $171 | 4 | 27,618 | $106 | 2 | 34,663 | $0 | 1 | 317,054 | 109,082 | 9 |
| Integrated No CCS MN | 28,345 | $1,283 | 6 | 28,886 | $1,374 | 6 | 35,768 | $1,105 | 6 | 386,023 | 178,051 | 13 |
| Integrated No Nuclear MN | 28,878 | $1,816 | 9 | 29,301 | $1,789 | 8 | 36,457 | $1,794 | 7 | 320,486 | 112,515 | 10 |
| Integrated No Coal Post 2032 MN | 28,438 | $1,376 | 7 | 29,235 | $1,723 | 7 | 36,751 | $2,088 | 8 | 215,237 | 7,265 | 3 |
| Integrated Offshore Wind MN | 34,645 | $7,583 | 13 | 35,127 | $7,615 | 13 | 42,917 | $8,255 | 13 | 310,014 | 102,043 | 7 |
| Integrated No Future Tech MN | 29,110 | $2,048 | 10 | 29,534 | $2,022 | 10 | 36,946 | $2,284 | 10 | 330,034 | 122,063 | 11 |
| Integrated Geothermal MN | 29,208 | $2,146 | 11 | 29,946 | $2,434 | 11 | 37,188 | $2,525 | 11 | 310,138 | 102,167 | 8 |
| Integrated Hunter Retire MN | 27,062 | $0 | 1 | 27,765 | $253 | 3 | 34,960 | $297 | 3 | 269,208 | 61,237 | 6 |
| Integrated Base MR | 27,176 | $114 | 3 | 27,913 | $401 | 4 | 35,385 | $723 | 5 | 207,971 | 0 | 1 |
| Integrated No CCS MR | 28,581 | $1,519 | 8 | 29,374 | $1,862 | 9 | 36,896 | $2,233 | 9 | 213,302 | 5,331 | 2 |
| Integrated Base LN | 27,785 | $723 | 5 | 27,970 | $458 | 5 | 35,167 | $504 | 4 | 340,068 | 132,096 | 12 |
| Integrated Base HH | 27,119 | $57 | 2 | 27,512 | $0 | 1 | 34,714 | $51 | 2 | 238,450 | 30,479 | 4 |
| Integrated Base SC | 29,787 | $2,725 | 12 | 30,088 | $2,575 | 12 | 37,904 | $3,242 | 12 | 257,126 | 49,155 | 5 |

Table 9.35, below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero $CO_2$) price-policy scenario.

**Table 9.35 –Integrated Portfolios Under Low Gas/ Zero $CO_2$**

| | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| Case - LN | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2025-2045 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base LN | 25,113 | $498 | 4 | 315,803 | 54,380 | 10 |
| Integrated Base MN | 25,226 | $611 | 5 | 334,470 | 73,047 | 12 |
| Integrated No CCS MN | 25,847 | $1,232 | 8 | 361,938 | 100,514 | 13 |
| Integrated No Nuclear MN | 28,638 | $4,023 | 12 | 315,004 | 53,580 | 9 |
| Integrated No Coal Post 2032 MN | 25,428 | $814 | 6 | 261,423 | 0 | 4 |
| Integrated Offshore Wind MN | 37,505 | $12,890 | 13 | 299,472 | 38,049 | 7 |
| Integrated No Future Tech MN | 26,507 | $1,892 | 9 | 326,791 | 65,368 | 11 |
| Integrated Geothermal MN | 26,936 | $2,322 | 10 | 300,704 | 39,281 | 8 |
| Integrated Hunter Retire MN | 24,959 | $344 | 2 | 273,675 | 12,251 | 6 |
| Integrated Base MR | 24,615 | $0 | 1 | 254,697 | (6,726) | 2 |
| Integrated No CCS MR | 25,580 | $965 | 7 | 261,242 | (181) | 3 |
| Integrated Base HH | 24,990 | $375 | 3 | 248,840 | (12,584) | 1 |
| Integrated Base SC | 27,805 | $3,190 | 11 | 270,860 | 9,437 | 5 |

Table 9.36 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high $CO_2$) price-policy scenario.

**Table 9.36 – Integrated Portfolios Under High Gas and Coal/ High $CO_2$**

| Case - HH | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2025-2045 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| **Integrated Base HH** | 31,498 | $0 | 1 | 174,521 | 444 | 2 |
| **Integrated Base MN** | 34,498 | $3,000 | 8 | 232,976 | 58,900 | 13 |
| **Integrated No CCS MN** | 35,762 | $4,264 | 11 | 219,378 | 45,302 | 12 |
| **Integrated No Nuclear MN** | 35,275 | $3,777 | 10 | 202,255 | 28,178 | 10 |
| **Integrated No Coal Post 2032 MN** | 33,052 | $1,553 | 4 | 179,879 | 5,803 | 4 |
| **Integrated Offshore Wind MN** | 45,727 | $14,228 | 13 | 194,780 | 20,703 | 8 |
| **Integrated No Future Tech MN** | 35,902 | $4,404 | 12 | 207,187 | 33,110 | 11 |
| **Integrated Geothermal MN** | 35,247 | $3,749 | 9 | 189,861 | 15,785 | 7 |
| **Integrated Hunter Retire MN** | 31,973 | $475 | 3 | 179,948 | 5,871 | 5 |
| **Integrated Base MR** | 31,796 | $297 | 2 | 180,431 | 6,355 | 6 |
| **Integrated No CCS MR** | 33,110 | $1,612 | 5 | 178,538 | 4,461 | 3 |
| **Integrated Base LN** | 33,995 | $2,496 | 6 | 201,609 | 27,532 | 9 |
| **Integrated Base SC** | 34,207 | $2,709 | 7 | 174,077 | 0 | 1 |

Table 9.37 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario.

**Table 9.37 – Integrated Portfolios Under Medium Gas/ Social Cost of $CO_2$**

| | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| Case - SC | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2025-2045 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| **Integrated Base SC** | 40,268 | $2,628 | 7 | 103,326 | 3,072 | 3 |
| **Integrated Base MN** | 40,882 | $3,242 | 8 | 117,244 | 16,990 | 9 |
| **Integrated No CCS MN** | 41,851 | $4,210 | 11 | 120,282 | 20,028 | 12 |
| **Integrated No Nuclear MN** | 38,899 | $1,258 | 4 | 115,060 | 14,806 | 8 |
| **Integrated No Coal Post 2032 MN** | 39,186 | $1,545 | 5 | 105,996 | 5,742 | 5 |
| **Integrated Offshore Wind MN** | 51,719 | $14,079 | 13 | 110,124 | 9,870 | 7 |
| **Integrated No Future Tech MN** | 41,797 | $4,157 | 10 | 117,608 | 17,354 | 10 |
| **Integrated Geothermal MN** | 40,942 | $3,302 | 9 | 106,062 | 5,808 | 6 |
| **Integrated Hunter Retire MN** | 38,034 | $394 | 2 | 101,094 | 840 | 2 |
| **Integrated Base MR** | 38,708 | $1,067 | 3 | 117,634 | 17,380 | 11 |
| **Integrated No CCS MR** | 39,227 | $1,586 | 6 | 104,731 | 4,477 | 4 |
| **Integrated Base LN** | 42,873 | $5,232 | 12 | 157,891 | 57,637 | 13 |
| **Integrated Base HH** | 37,640 | $0 | 1 | 100,254 | 0 | 1 |

**Integrated Portfolios Under Medium Gas/ Federal Regulation (MR)**

Three variant cases examined compliance under the current language in EPA 111(d): the base MR case, the MR No CCS case, and the No Coal Post-2032 case. Details for each MR case is included with the discussions of the integrated portfolio results below.

## Variant Study Analysis

**No CCS Variant**

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were found not to be commercially viable at this location. As Jim Bridger 3 and 4 run as coal in this case, the No CCS variant serves as the "All Coal End of Life" variant as well.

Figure 9.17 shows the cumulative (at left) and incremental (at right) portfolio changes when CCS at Jim Bridger 3 and 4 is not allowed on the system starting in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Over the course of the horizon, fewer proxy resources are built. There is reduction of 469 MW of wind, 236 MW of solar and 989 MW of battery, with battery reductions occurring in 2042 and 2045.

**Figure 9.17 - Increase/(Decrease) in Proxy Resources with No CCS**

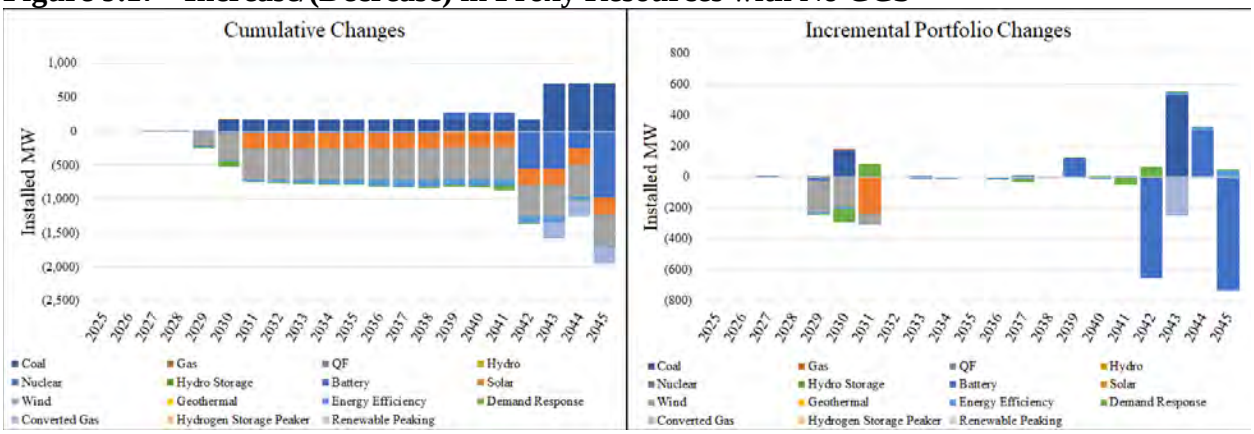
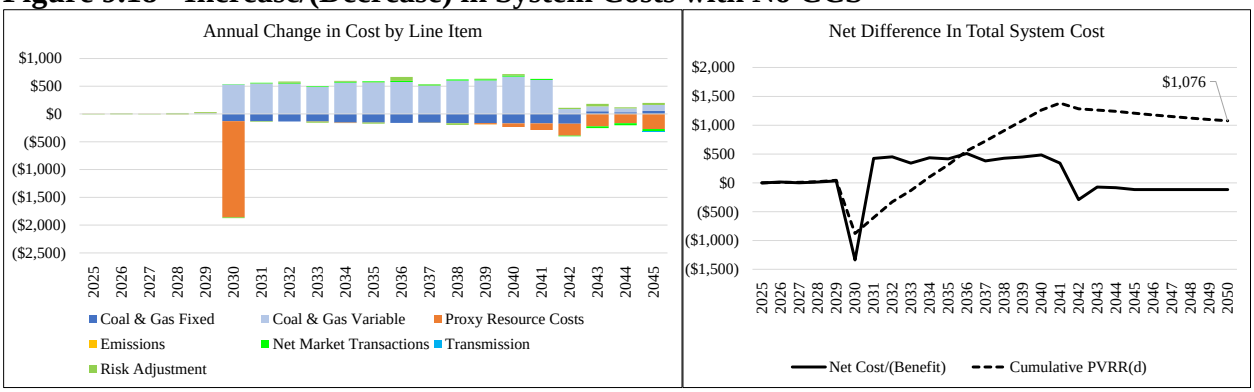



Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.076 billion increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

**Figure 9.18 - Increase/(Decrease) in System Costs with No CCS**




## No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2032. Additionally, this variant does not allow any proxy nuclear to be selected as a potential replacement for the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the nuclear projects prove unviable.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case does not select small renewable peaking resources and reduces 100-hour battery selection by 1,955 MW. The No Nuclear portfolio does add an additional 923 MW of 4-hour storage, 347 MW

of wind, 296 MW of solar, and 120 MW of DSM. This study also keeps the CCS at Jim Bridger and Naughton 1 gas conversion through the end of the study horizon.

**Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Nuclear**

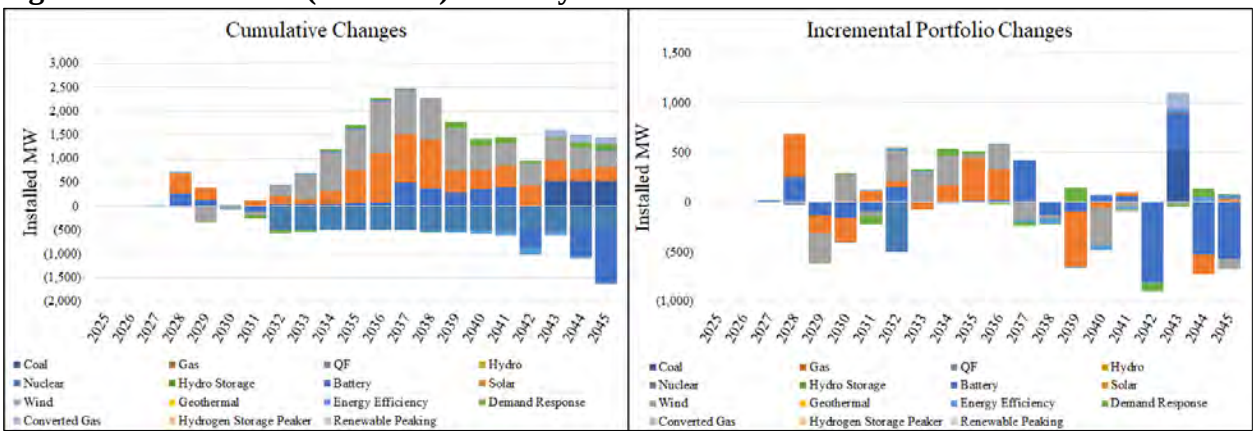
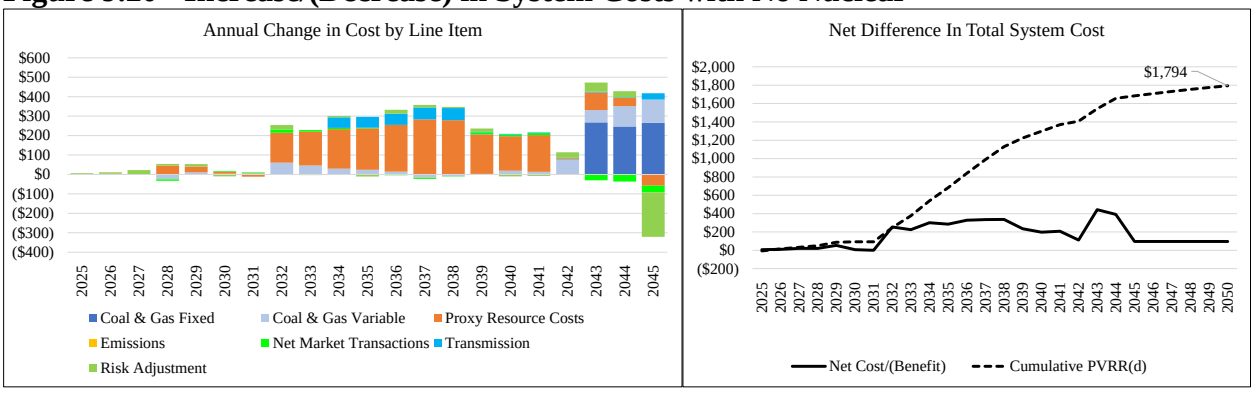



Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.794 billion increase in costs compared to the preferred portfolio. Given that no costs associated with the Natrium™ demonstration project are included in modeling, the increase in costs reflects the loss of all energy and PTC benefits associated with the project.

As seen in Figure 9.20 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

**Figure 9.20 - Increase/(Decrease) in System Costs with No Nuclear**




## No Coal Post-2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS. Because all units eligible for gas conversion either convert to gas or retire early, this study also serves as the "Force Gas Conversion" variant.

Figure 9.21 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects additional energy efficiency and demand response, over 2,200 MW of additional wind and solar, and a shift in storage from 4-hour to long duration.

**Figure 9.21 - Increase/(Decrease) in Proxy Resources with No Coal Post-2032**

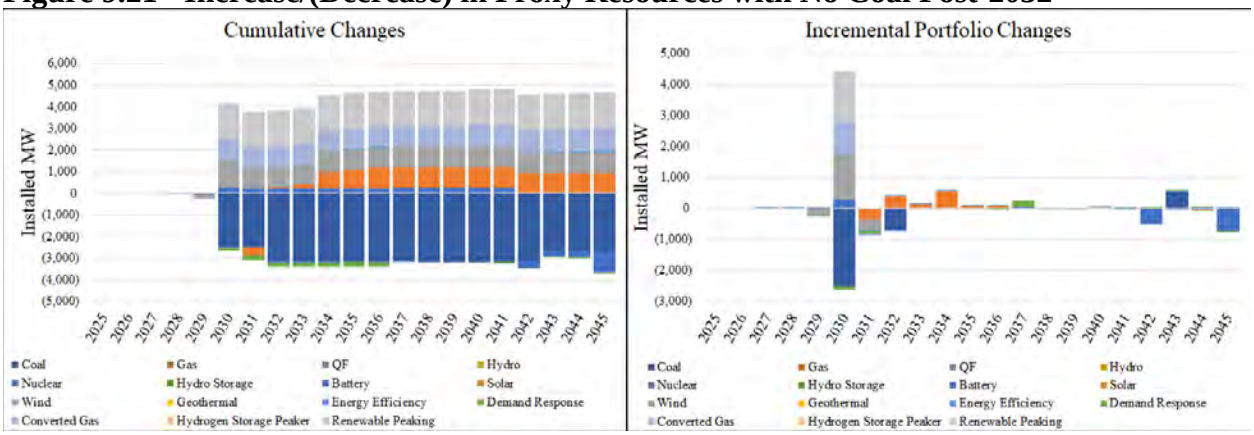
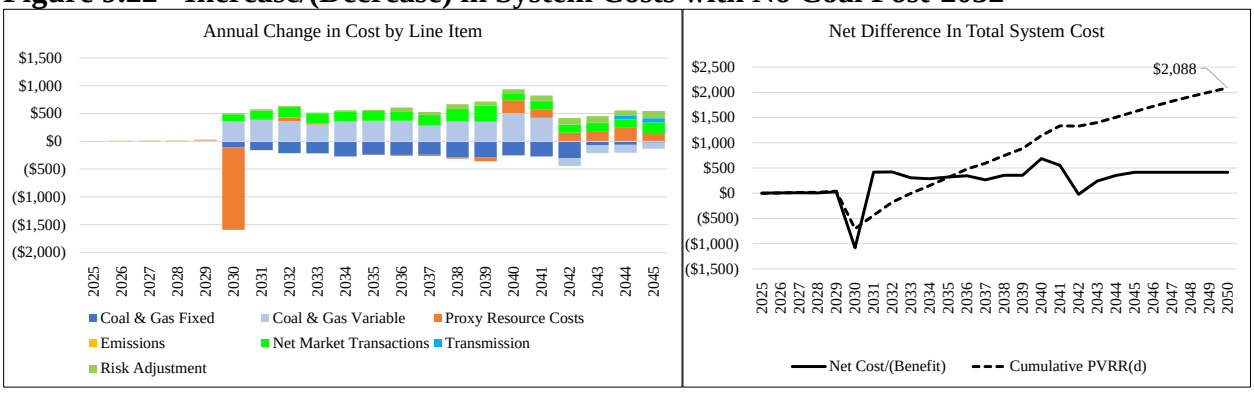



Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or converted to gas by 2032, the resulting portfolio has a $2.088 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.22 below, the system cost increase exceeds the impact of 45Q tax credits and CCS capital cost. Additionally, this case has higher levels of market purchases and has higher proxy resource costs in nearly all years of the study horizon.

**Figure 9.22 - Increase/(Decrease) in System Costs with No Coal Post-2032**



**Force Offshore Wind**

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 9.23 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2033. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The portfolio selects and additional 120 total MW of wind, 3,760 MW of 4-hour storage and 35 MW of additional DSM. These increased selections are partially offset by a reduction of 132 MW of solar and 812 MW of 100-hour storage. Retirements are the same between the studies.

**Figure 9.23 - Increase/(Decrease) in Proxy Resources with Offshore Wind**

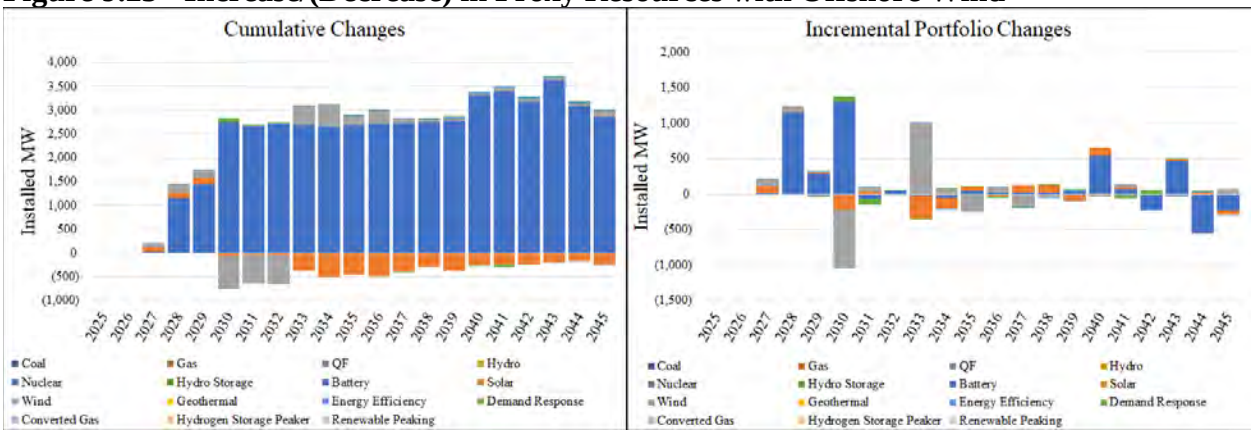
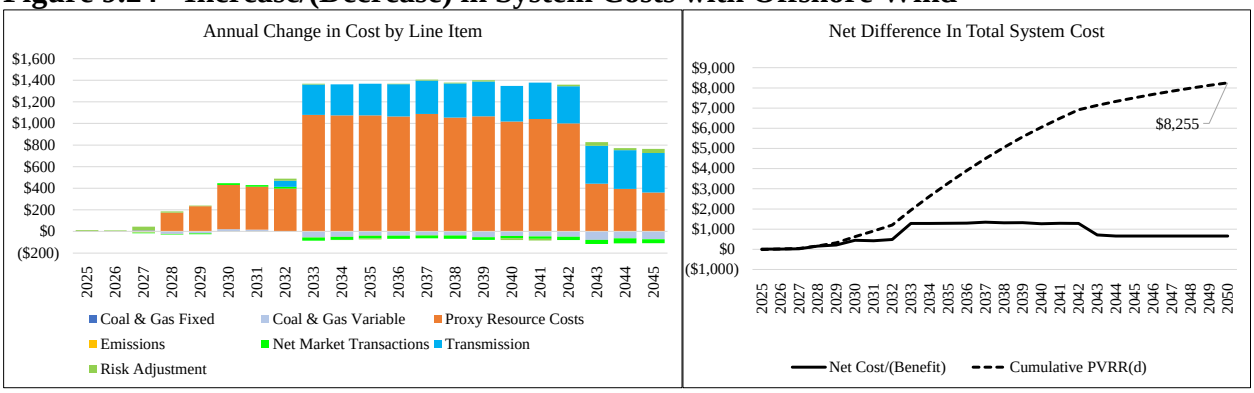



Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $8.255 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.24 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

**Figure 9.24 - Increase/(Decrease) in System Costs with Offshore Wind**




## No Forward Technology

This variant does not allow the Natrium™ demonstration nuclear project, hydrogen storage, 100-hour battery or small biodiesel peaking units to be selected as resource options. The analysis explores the potential costs and benefits of replacement resource options should these technologies not become commercially viable during the assumed time frame as modeled.

Figure 9.25 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case selects 120 MW of additional DSM, 187 MW of additional wind and 254 additional MW of solar. The model replaces the 3,073 MW of 100-hour storage with 1,826 MW of 4-hour storage and also does not retire CCS at Jim Bridger or the Naughton 1 gas conversion.

**Figure 9.25 - Increase/(Decrease) in Proxy Resources with No Forward Technology**

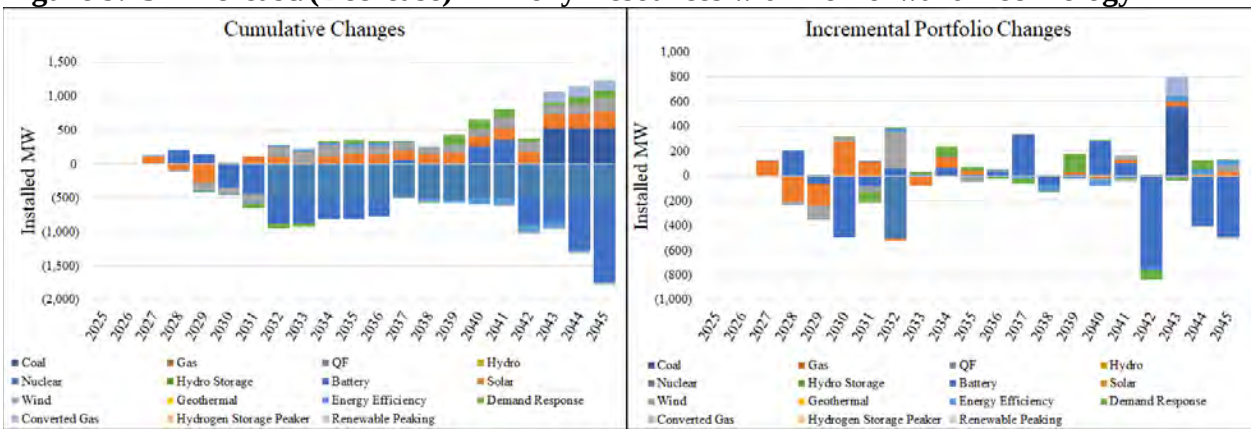
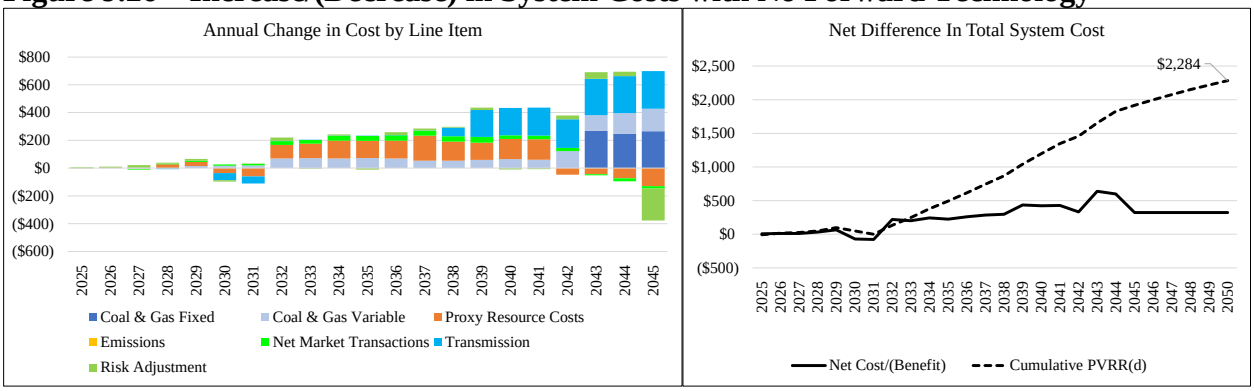



Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all forward technology is removed from the portfolio, the resulting portfolio has a $2.284 billion increase in costs compared to the preferred portfolio, somewhat higher than the impact of removing Natrium™ alone as shown in Figure 9.20.

As seen in Figure 9.26 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease

in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

**Figure 9.26 – Increase/(Decrease) in System Costs with No Forward Technology**




## Force Geothermal

Since geothermal was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor geothermal resource.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when geothermal is forced into the portfolio by 2028. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The geothermal study does not retire the Naughton 1 gas conversion. Additionally, the firm capacity more than 700 MW of geothermal reduces the need for other renewable resources. Over 2,500 MW of wind and solar are removed, as well as over 2,200 MW of long duration storage. 719 MW of 4-hour storage is selected in the geothermal study.

**Figure 9.27 - Increase/(Decrease) in Proxy Resources with Geothermal**

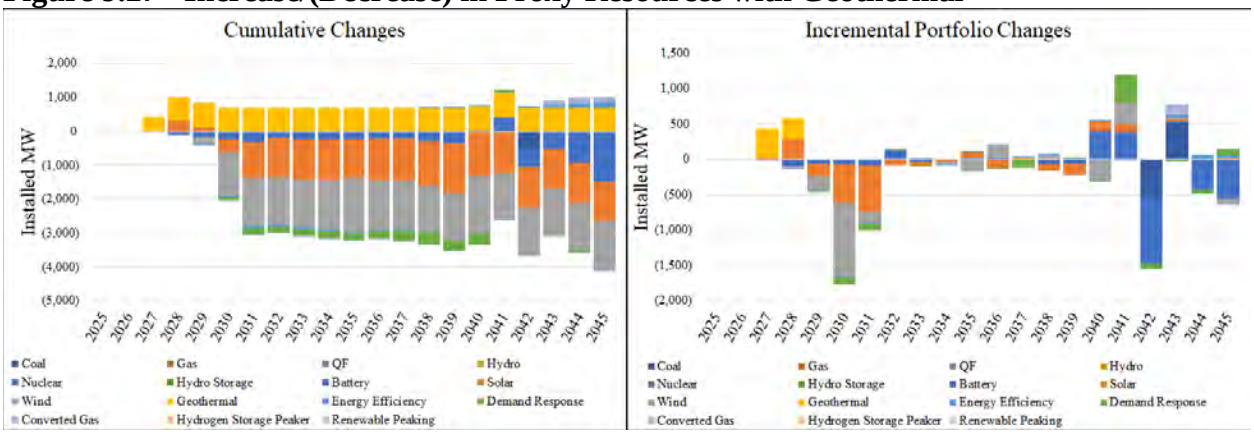
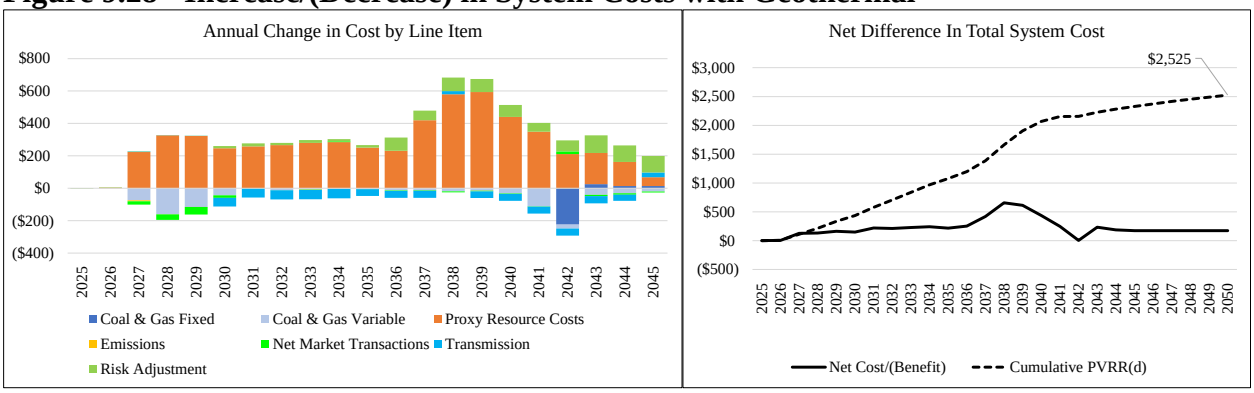



Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the geothermal is forced into the portfolio, the resulting portfolio has a $2.525 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.28 below, these increases come primarily from increased costs of the geothermal compared to the lower costs of the renewable resources that were replaced by the geothermal.

**Figure 9.28 - Increase/(Decrease) in System Costs with Geothermal**




## Force Hunter Retirement

Responsive to stakeholder request, PacifiCorp performed a variant analysis exploring what the impact of an early retirement of the Hunter plant would be on the portfolio. In this variant, all units at Hunter were required to retire by 2030. The analysis explores the potential costs and benefits of replacing the Hunter plant with resources selected in the UIWC jurisdictional portfolio when Hunter is not available. Additional consideration of Utah regulations would be necessary before the company would be able to move forward with implementing this variant.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when Hunter is forced to retire in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The Hunter study does not retire the Naughton 1 gas conversion. The loss of 1,100 MW of firm capacity in 2030 leads to the selection of over 1,100 MW of wind and solar, coupled with 866 MW of additional storage in 2030. By the end of the study horizon, the model selects 99 MW of new gas, an additional 355 MW of energy efficiency and demand response, and over 1,400 MW of new renewables. Total battery selection over the horizon stays the same but has a shift from 4-hour to 100-hour storage.

**Figure 9.29 - Increase/(Decrease) in Proxy Resources with Hunter Retirement**

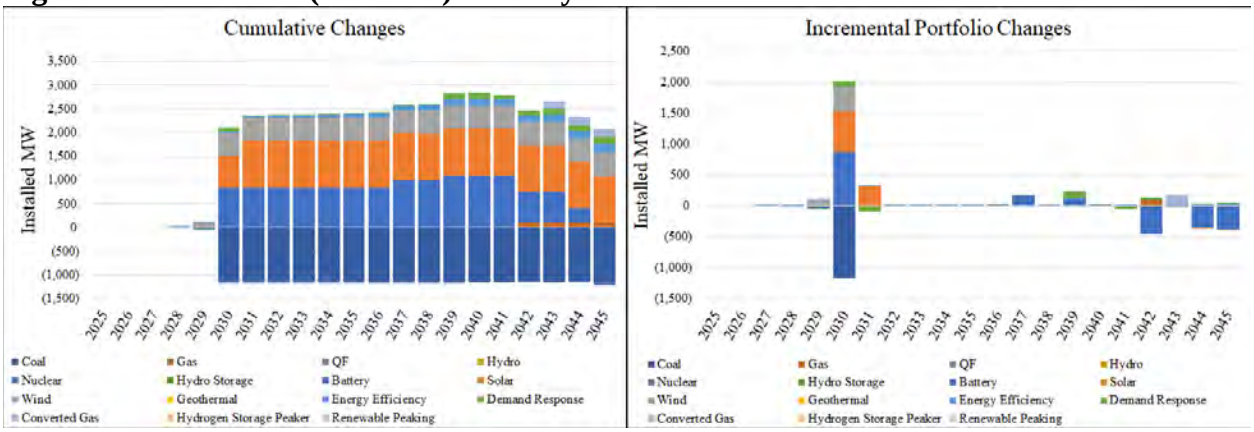
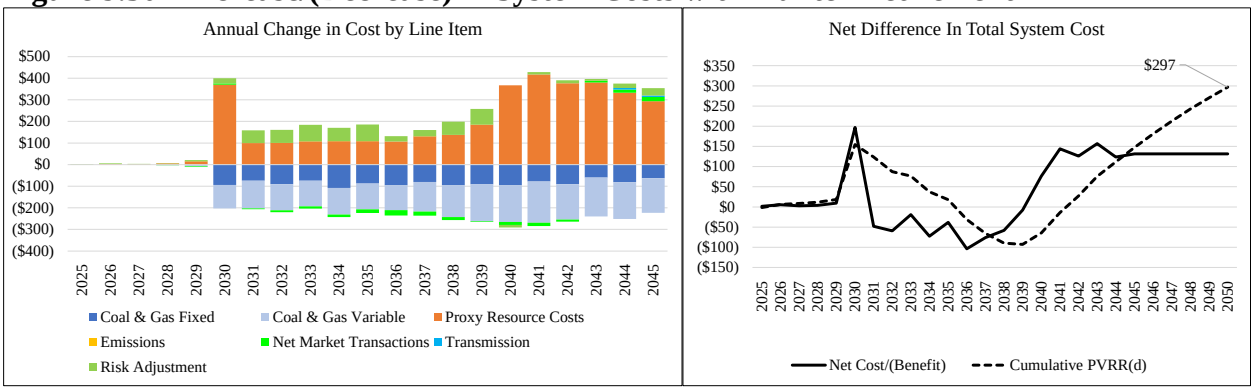


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Hunter is forced to retire in 2030, the resulting portfolio has a $297 million increase in costs compared to the preferred portfolio.

As seen in Figure 9.30 below, these increases come primarily from the additional proxy resource costs associated with replacing the Hunter plant in 2030.

**Figure 9.30 - Increase/(Decrease) in System Costs with Hunter Retirement**




## MR Portfolio

The MR portfolio evaluates resource selections assuming EPA 111(d) rules remain in effect through the study horizon. This portfolio limits new gas capacity factors and requires either installation of CCS, gas conversion, or retirement of existing coal units by 2032. The purpose of this study is to evaluate a path PacifiCorp would pursue for long-term compliance with this rule.

Figure 9.31 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In an MR future, all plants that are eligible to convert from using coal to using a different fuel type do. Wyodak and Hunter 1 both retire in 2032. This reduction in coal capacity and the significantly lower capacity factor of converted units leads to an additional 1,299 MW of solar, 916 MW of wind and 369 MW of DSM. The portfolio also selects 451 MW of additional 100-hour battery, while removing 575 MW of 4-hour storage.

**Figure 9.31 - Increase/(Decrease) in Proxy Resources with MR**

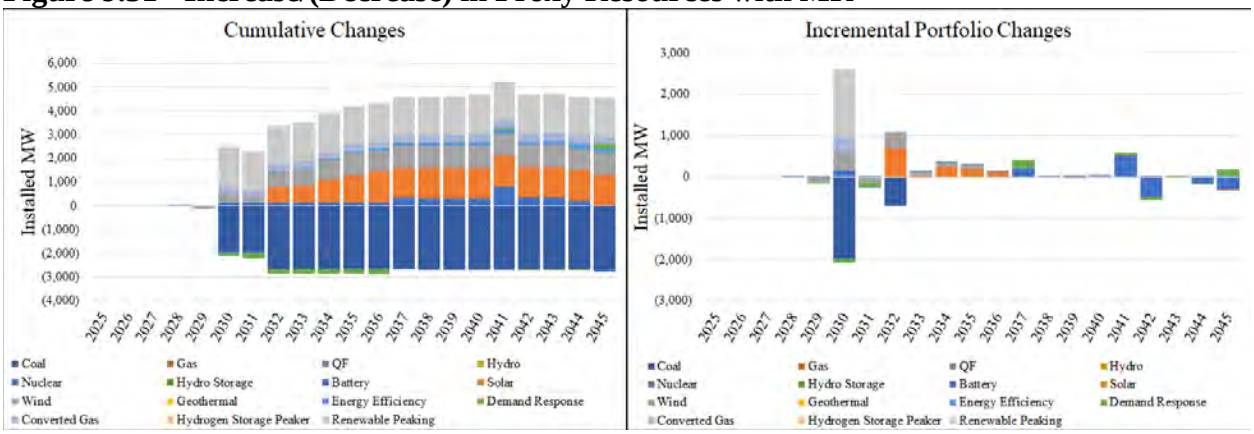
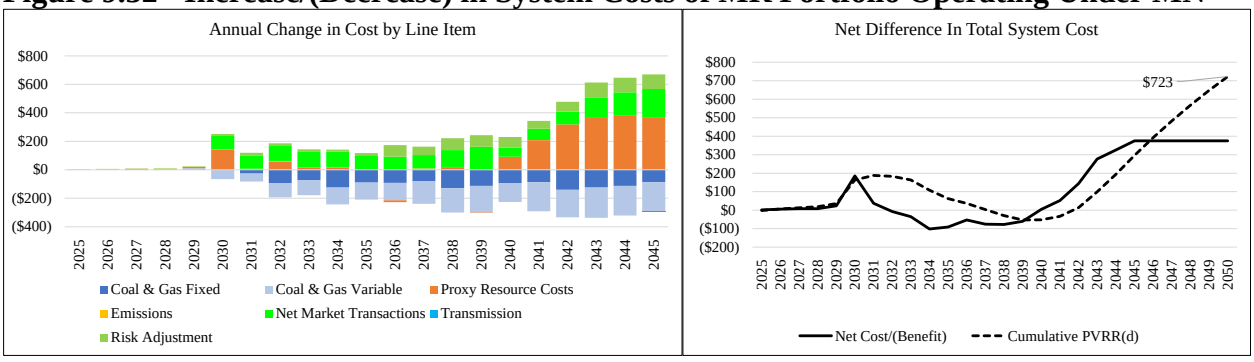



Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the MR portfolio is operating under the MN price policy, the resulting portfolio has a $723 million increase in costs compared to the preferred portfolio.

**Figure 9.32 - Increase/(Decrease) in System Costs of MR Portfolio Operating Under MN**




## MR No CCS

The MR No CCS portfolio evaluates what changes would occur to the MR portfolio if CCS at Jim Bridger were to prove to not be a viable option for EPA 111(d) compliance. This portfolio limits new gas capacity factors and requires either gas conversion, or retirement of existing coal units by 2032, precluding CCS selections. The purpose of this study is to evaluate the path PacifiCorp would take to be compliant with this rule in the absence of CCS at Bridger.

Figure 9.33 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Jim Bridger 3 and 4 gas convert in lieu of installing CCS and does not retire Naughton 1 gas conversion. Hunter 1 retires in 2031 instead of 2032. Keeping the Jim Bridger and Naughton units leads to lower proxy resource selections across all generating types. The portfolio reduces wind by 55 MW, DSM by 378 MW and solar by 561 MW. Battery selections remain cumulatively the same with a shift from 24-hour battery to 4-hour battery.

**Figure 9.33 - Increase/(Decrease) in Proxy Resources with MR No CCS vs. MR**

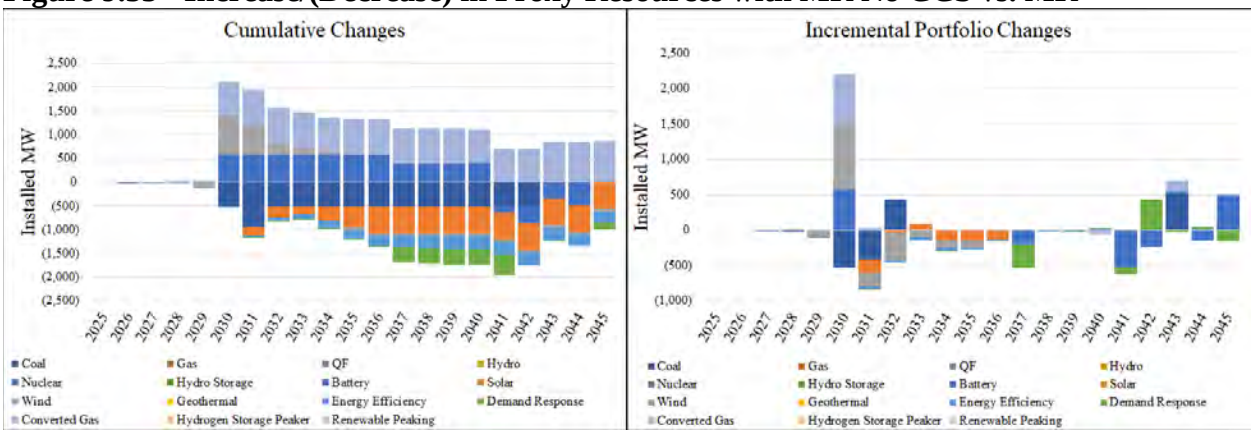
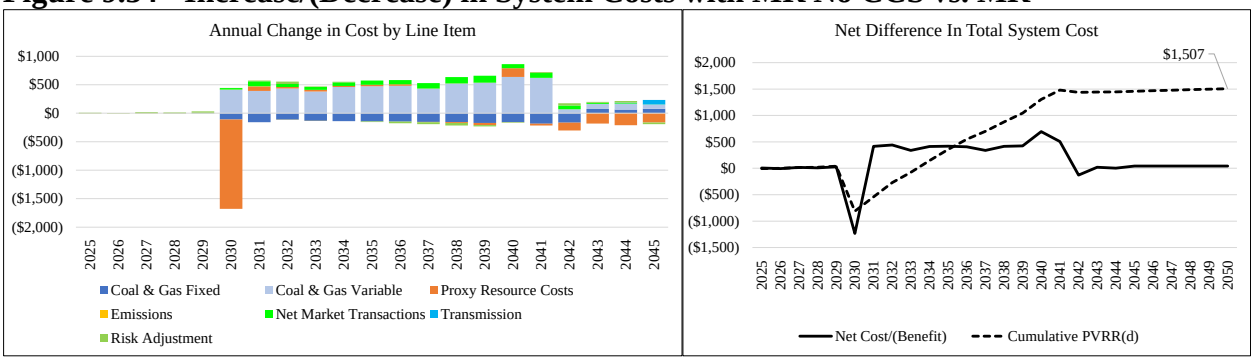



Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.507 billion increase in costs compared to the MR portfolio with CCS.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

**Figure 9.34 - Increase/(Decrease) in System Costs with MR No CCS vs. MR**




## HH Portfolio

The HH portfolio evaluates what selections would be made under high future costs, including gas, market, and coal. This portfolio integrated Oregon selections under HH, UIWC selections under HH and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a high-cost future was most likely.

Figure 9.35 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a high price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The HH Portfolio selects Dave Johnston 4 and Hunter 2 to convert from coal to a different fuel in 2030. The HH also retires Hunter 2 in 2033. The model increases brownfield renewable selections by 2007 MW and selects 562 additional MW of 100-hour storage. There is a reduction in 4-hour

storage of 757 MW, however all selections of additional 4-hour storage occur in 2030 in the HH run. An additional 208 MW of DSM is also selected.

**Figure 9.35 - Increase/(Decrease) in Proxy Resources with HH**

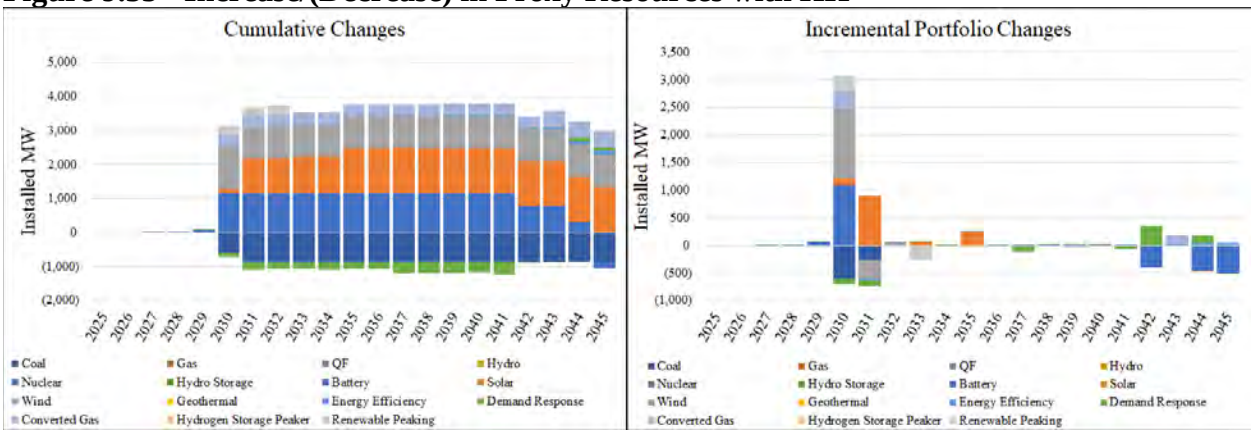
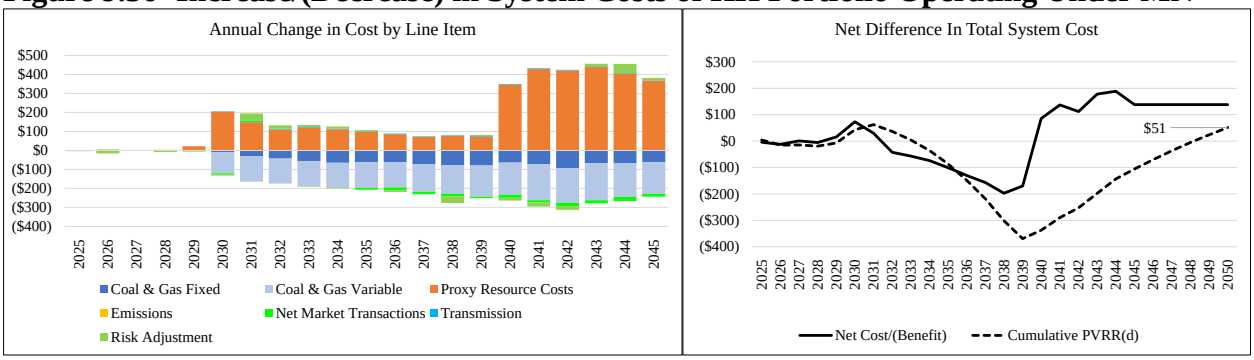



Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the HH portfolio is operating under the MN price policy, the resulting portfolio has a $51 million increase in costs compared to the preferred portfolio.

**Figure 9.36- Increase/(Decrease) in System Costs of HH Portfolio Operating Under MN**



### LN Portfolio

The LN portfolio evaluates what selections would be made under low future costs, including gas and market with no $CO_2$ tax adder. This portfolio integrated Oregon selections under LN, UIWC selections under LN and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a low-cost future was most likely.

Figure 9.37 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a low-price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The LN portfolio delays the retirement of the Jim Bridger CCS conversions one year and does not retire Naughton 1. The LN does select 496 MW of new gas peaking units in 2045 in place of the 41 MW of renewable peaking in the preferred portfolio. There is an increase of 91 MW of DSM, and a reduction of 508 MW of new renewable generation. The model selects and additional 389 MW of storage, swapping 100-hour for 4-hour battery.

**Figure 9.37 - Increase/(Decrease) in Proxy Resources with LN**

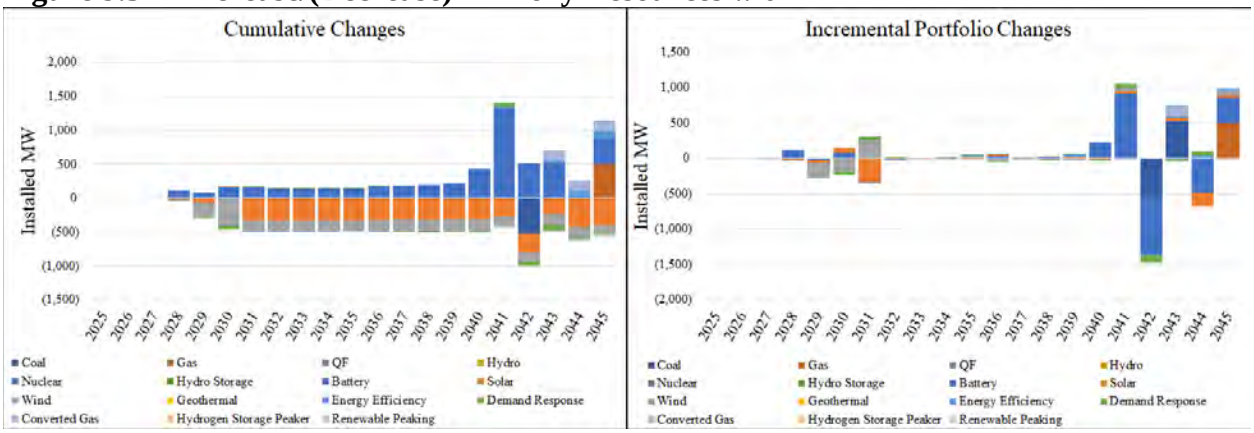
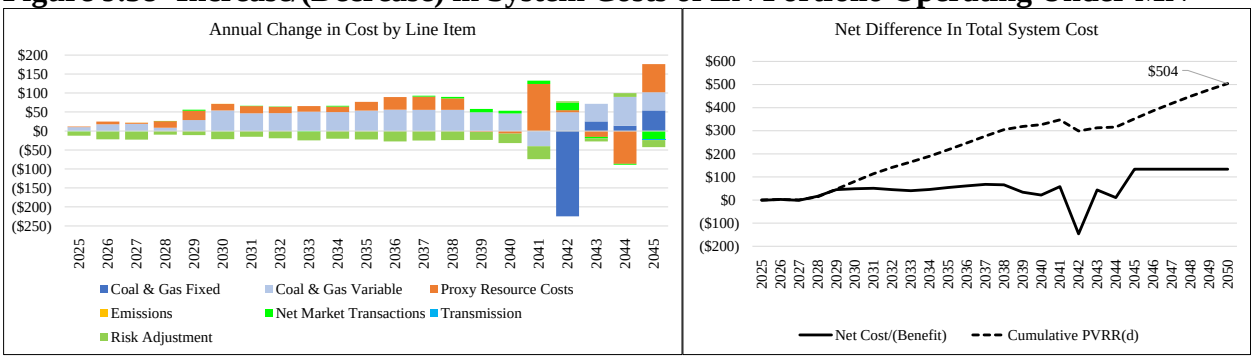



Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the LN portfolio is operating under the MN price policy, the resulting portfolio has a $504 million increase in costs compared to the preferred portfolio.

**Figure 9.38- Increase/(Decrease) in System Costs of LN Portfolio Operating Under MN**



## SCGHG Portfolio

The SCGHG portfolio evaluates what selections would be made under a Social Cost of Greenhouse Gas future. This portfolio integrated all jurisdiction's selections under SCGHG. The purpose of this study is to evaluate the selections PacifiCorp would make if an SCGHG future was most likely.

Figure 9.39 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and an SCGHG future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The SCGHG portfolio does not retire the Jim Bridger CCS conversions or Naughton 1 but does retire Wyodak in 2028 and the Dave Johnston 1 gas conversion in 2043. Additionally, the SCGHG case chooses gas conversion at Dave Johnston 4 and allows it to continue through the 21-year horizon and does not retire Naughton 1. The SCGHG case selects an additional 999 MW of utility scale wind, 1,269 MW of utility scale solar, 1,756 MW of 4-hour battery and 240 MW of DSM. The portfolio reduces small scale solar selections by 101 MW and 100-hour storage by 126 MW.

**Figure 9.39 - Increase/(Decrease) in Proxy Resources with SCGHG**

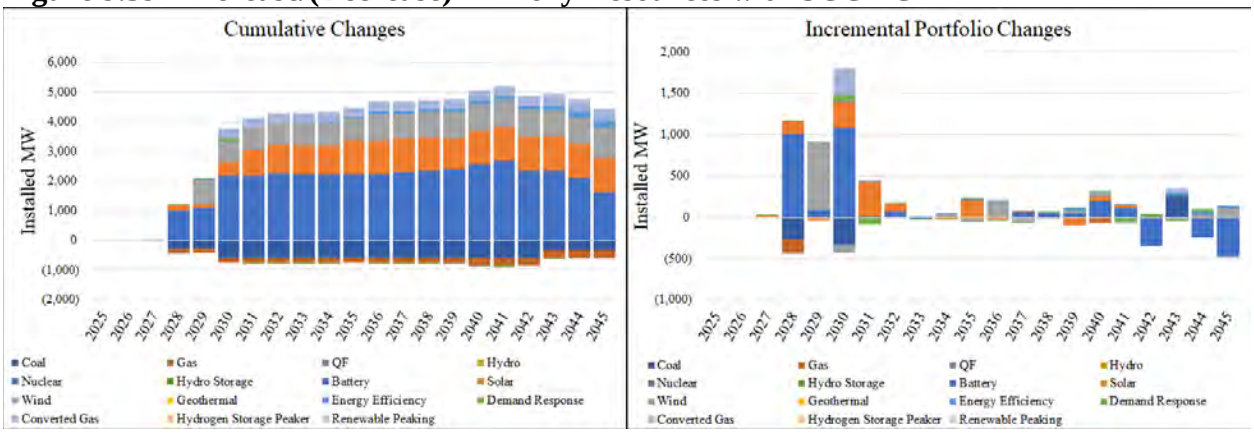
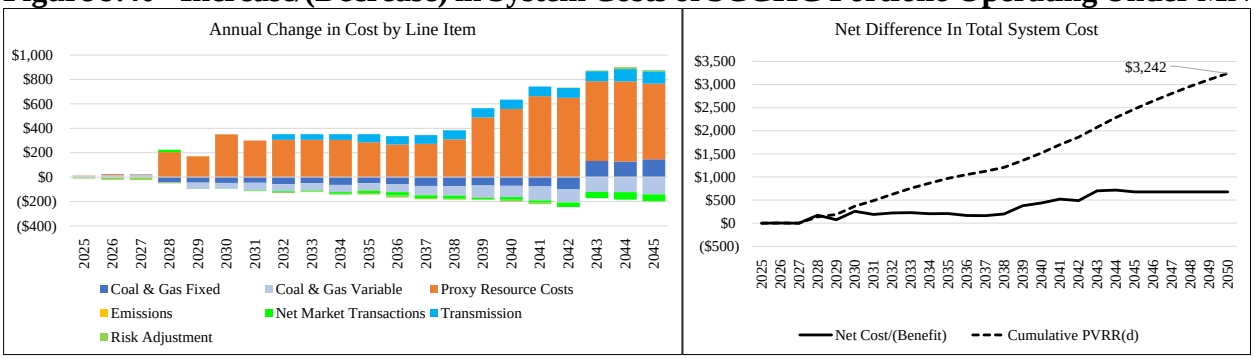



Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the SCGHG portfolio is operating under the MN price policy, the resulting portfolio has a $3.242 billion increase in costs compared to the preferred portfolio.

**Figure 9.40 - Increase/(Decrease) in System Costs of SCGHG Portfolio Operating Under MN**



## Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases were developed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. It is assumed that state level compliance would still be required to be met in these sensitivities; Oregon would still need to reduce emissions, and Washington would need to meet CETA targets. These sensitivity cases are also useful as "bookend" analysis to aid in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risks.

Table S.1 lists additional sensitivity studies to be performed for the 2025 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are evaluated in comparison to the preferred portfolio.

**Table S.1– Summary of Additional Sensitivity Cases**

| Sensitivity | Definition |
|---|---|
| High Load Growth | Base load forecast replaced by a high load version |
| Low Load Growth | Base load forecast replaced by a low load version |
| 1-20 Peak Load | Base load forecast replaced by a high load version using historical 20-year highest load |
| High Distributed Generation | Assumes lower load due to high Distributed Generation adoption |
| Low Distributed Generation | Assumes higher load due to low Distributed Generation adoption |
| Large-metered Load Growth | Assumes significant large-metered customer load growth |
| Low Cost Renewables | Assumes high adoption of IRA/IIJA benefits leads to large cost declines |
| Low PTC/ITC eligibility | Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window |
| All CCS | Allows CCS to be selected at additional coal units |
| Business as Usual | Portfolio if no state requirements existed |
| Business Plan[8] | First 3 years are aligned with the current business plan |

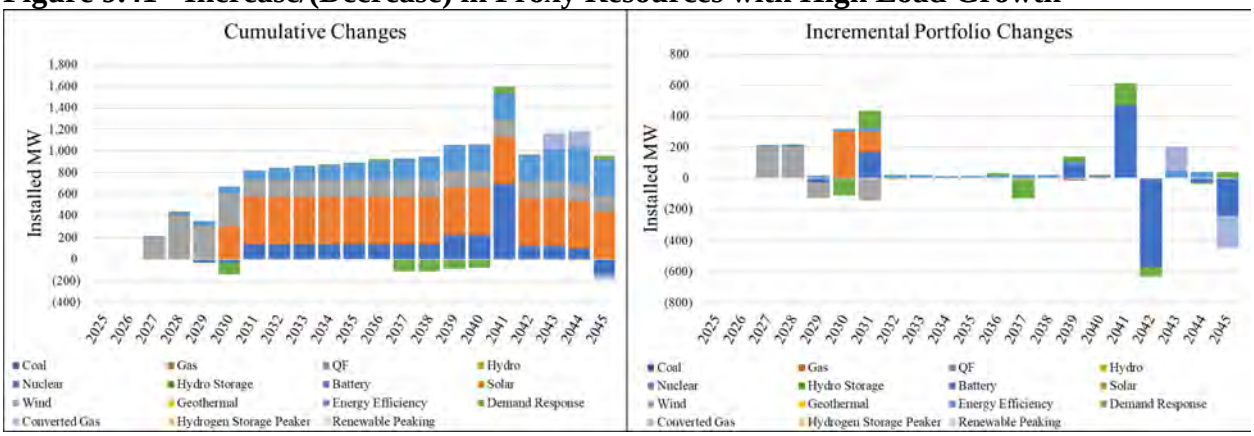
### High Load Growth

The High Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if load grows faster than anticipated.

Figure 9.41 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high load growth portfolio does not retire Naughton 1 but does retire Naughton 2 in 2045. The higher load growth leads to an additional 319 MW of DSM, 160 MW of wind, and 435 MW of solar. There is a total reduction of 137 MW of storage, with 329 fewer MW of 4-hour storage offset by 100 MW of 8-hour and 92 MW of 100-hour storage.

[8] In the 2025 IRP, the business plan sensitivity is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed.

**Figure 9.41 - Increase/(Decrease) in Proxy Resources with High Load Growth**

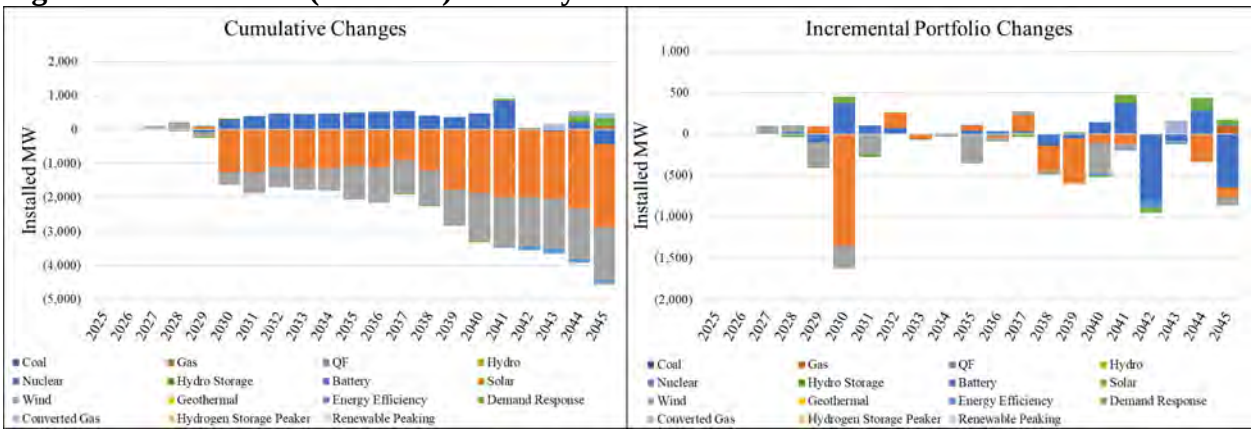



## Low Load Growth

The Low Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify which resources might be economic if load grows more slowly than anticipated.

Figure 9.42 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low load growth portfolio does not retire Naughton 1. Due to the lower need, the portfolio selects 1,566 MW less wind, 2,440 MW less solar and 425 MW less storage, with a reduction in 100-hour storage offset by additional 4-hour storage. The portfolio does select an additional 125 MW of DSM.

**Figure 9.42 - Increase/(Decrease) in Proxy Resources with Low Load Growth**



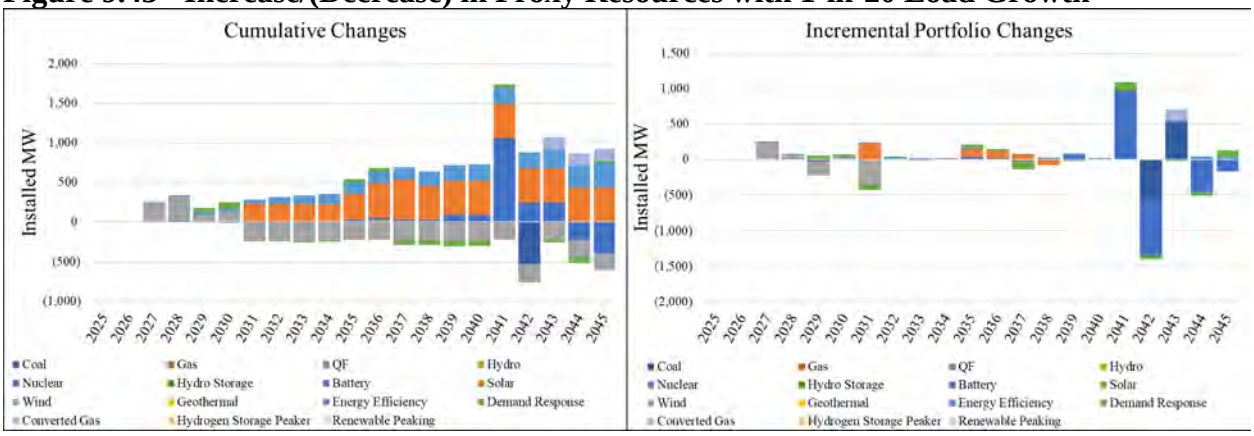

## 1-in-20 Peak Load Growth

The 1-in-20 Peak Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if peak load is higher than anticipated.

Figure 9.43 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and higher 1-20 peak loads. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The 1-20 peak

load portfolio retires the Jim Bridger CCS conversions 1 year later and does not retire Naughton 1. The higher peak loads lead to an additional 317 MW of DSM and 431 MW of additional solar. There is a reduction of 222 MW of wind and 385 MW of storage.

**Figure 9.43 - Increase/(Decrease) in Proxy Resources with 1-in-20 Load Growth**

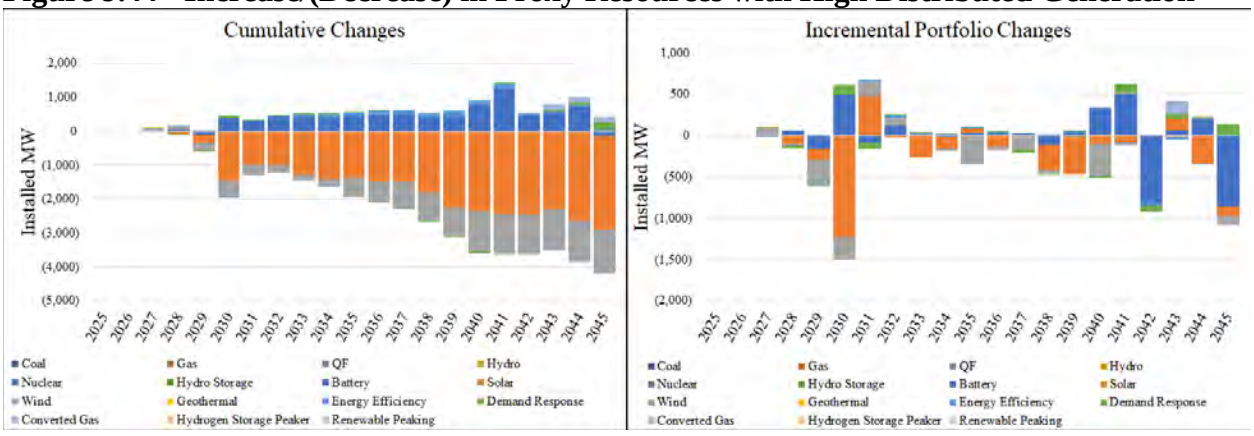



## High Distributed Generation Growth

The High Distributed Generation Growth sensitivity evaluates what selections would be made if distributed generation growth were higher than projected (and load was lower as a result). The purpose of this study is to identify which resources would be economic if load is lower than anticipated.

Figure 9.44 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high distributed generation growth portfolio selects an additional 269 MW of DSM. The portfolio reduces renewable resources by 4,078 MW and storage resources by 135 MW over the course of the 21-year horizon.

**Figure 9.44 - Increase/(Decrease) in Proxy Resources with High Distributed Generation**

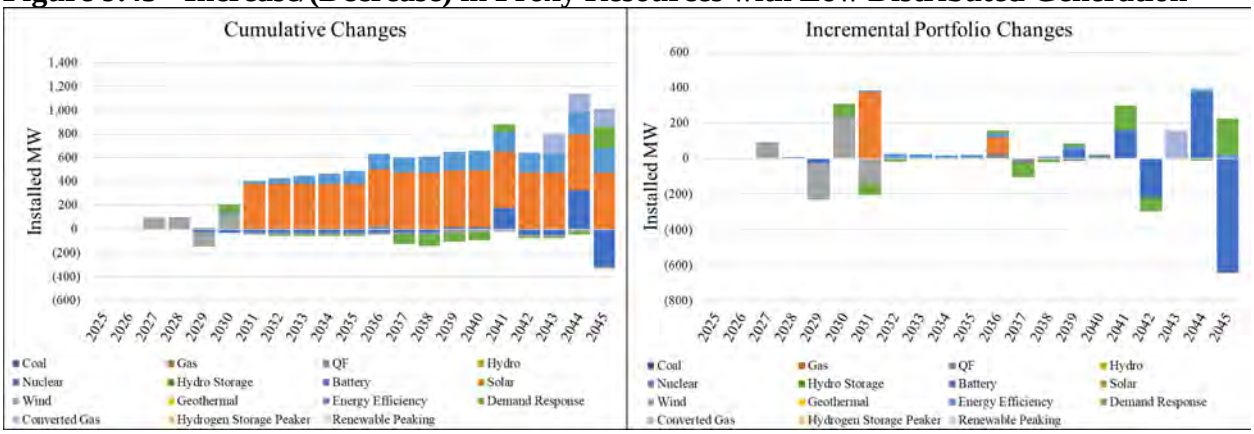



## Low Distributed Generation Growth

The low distributed generation growth sensitivity evaluates what selections would be made if distributed generation growth were lower than projected. The purpose of this study is to identify potential additional resource needs if distributed generation growth is lower than anticipated.

Figure 9.45 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low distributed generation portfolio does not retire Naughton 1. The higher load need leads to 349 additional MW of DSM and 471 MW of solar. There is a reduction of 15 MW of wind and 351 MW of 4-hour storage partially offset by an additional 40 MW of 100-hour storage.

**Figure 9.45 - Increase/(Decrease) in Proxy Resources with Low Distributed Generation**




## Large-Metered Load Growth

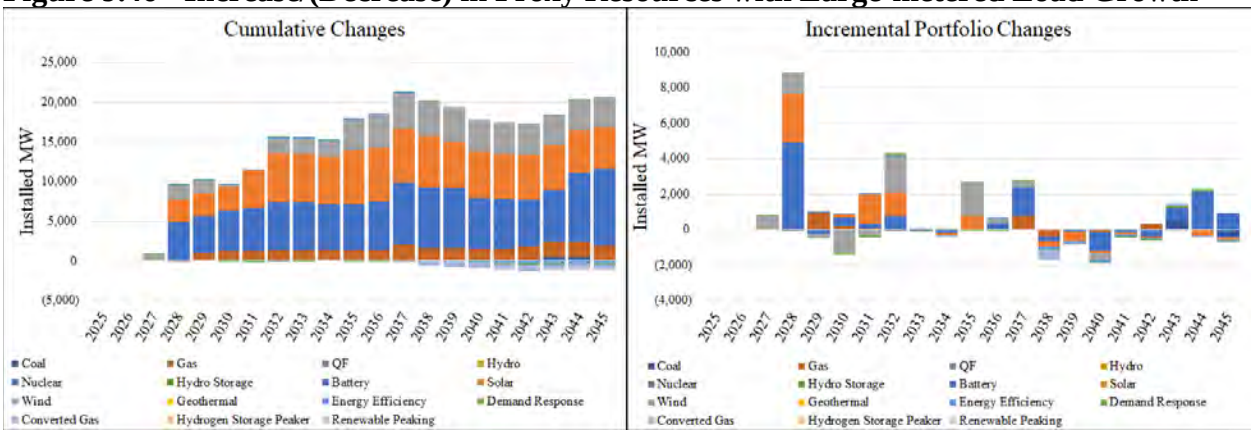
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the system had to serve all of these large-metered loads.

Figure 9.46 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This sensitivity selects 2,354 MW of gas peaking units, an additional 3,872 MW of utility scale wind, an additional 5,993 MW of utility scale solar and 9,650 MW of additional storage. In 2038, the large-metered load growth portfolio retires 804 MW of existing thermal units that were not retired in the preferred portfolio. In addition to significant resource additions, serving large-metered load requires significant transmission investments. Table 9.38 shows the transmission required in the large-metered load growth study.

**Table 9.38 – Large-metered Load Transmission Selections**

| Line | Year Selected |
|---|---|
| INC B2H2 Hemingway>Longhorn - 2033 | 2033 |
| INC BorahPop > Hemingway 2037 Segment E | 2037 |
| INC BorahPop > Wasatch Front 2035 D3.2 | 2044 |
| INC BorahPop > Wasatch Front 2035 D3.3 | 2035 |
| INC Bridger > BorahPop 2032 | 2032 |
| INC Bridger > BorahPop 2035 D3.2 | 2044 |
| INC Bridger > Wyoming East 2032 D2.2 | 2032 |
| INC Goshen > NUT 2035 1b | 2035 |
| INC NUT > Goshen 2029 | 2029 |
| INC NUT > Wasatch Front 2029 | 2029 |
| INC NUT > Wasatch Front 2030 2C7 3C6 | 2030 |
| INC Portland North Coast > Willamette Valley 2037 | 2037 |
| INC Portland North Coast > Yakima 2029 | 2029 |
| INC Utah South > Wasatch Front 2028B | 2028 |
| INC Utah South > Wasatch Front 2029 | 2029 |
| INC Utah South > Wasatch Front 2035 | 2035 |
| INC Willamette Valley > Central OR 2032 | 2032 |
| INC Willamette Valley > Southern OR 2036 | 2036 |
| INC Wyoming East > BorahPop 2035 D3.3 | 2035 |
| INC Wyoming East > Bridger 2032 | 2032 |
| INC Wyoming East > Clover 2035 GWS2 | 2044 |

**Figure 9.46 - Increase/(Decrease) in Proxy Resources with Large-metered Load Growth**



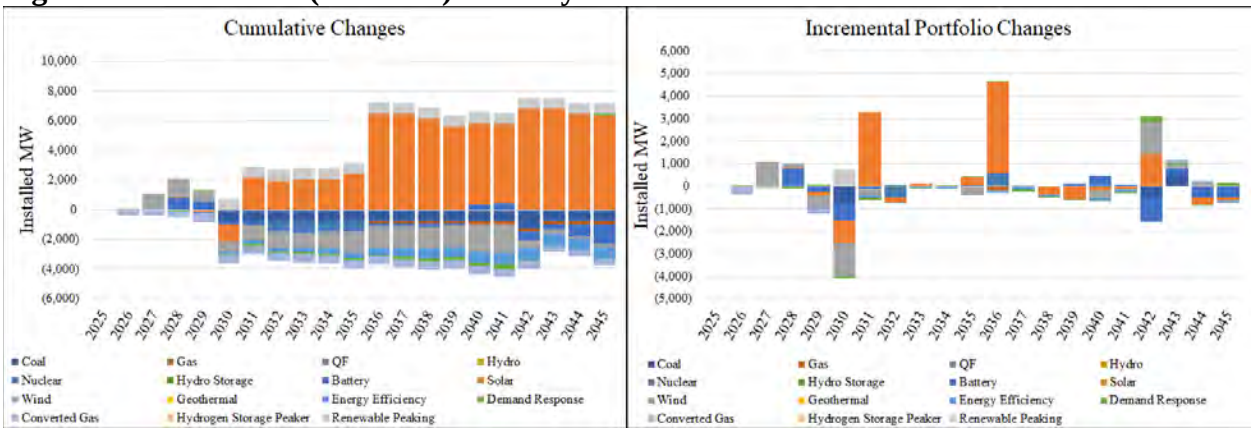

## Low-Cost Renewables

The low-cost renewables sensitivity evaluates what selections would be made if renewable resources were lower cost than the current modeling expectations. The purpose of this study is to identify potential additional resources if the company were able to take advantage of all tax credits and assumes advantageous financing to complete projects.

Figure 9.47 shows the cumulative (at left) and incremental (at right) portfolio changes between the preferred portfolio and a portfolio acquiring resources on the advantageous basis described above. A positive value indicates an increase in resources and a negative value indicates a decrease when

a resource is reduced or eliminated. The low-cost renewables portfolio selects 199 MW less wind, but 7,187 MW of additional utility scale solar. The model also selects 950 more MW of short and medium duration storage, but 2,549 MW less 100-hour battery. Of note, coal plants which are able to endogenously retire throughout the horizon convert to alternate fuels but do not retire under this sensitivity.

**Figure 9.47 - Increase/(Decrease) in Proxy Resources with Low-Cost Renewables**

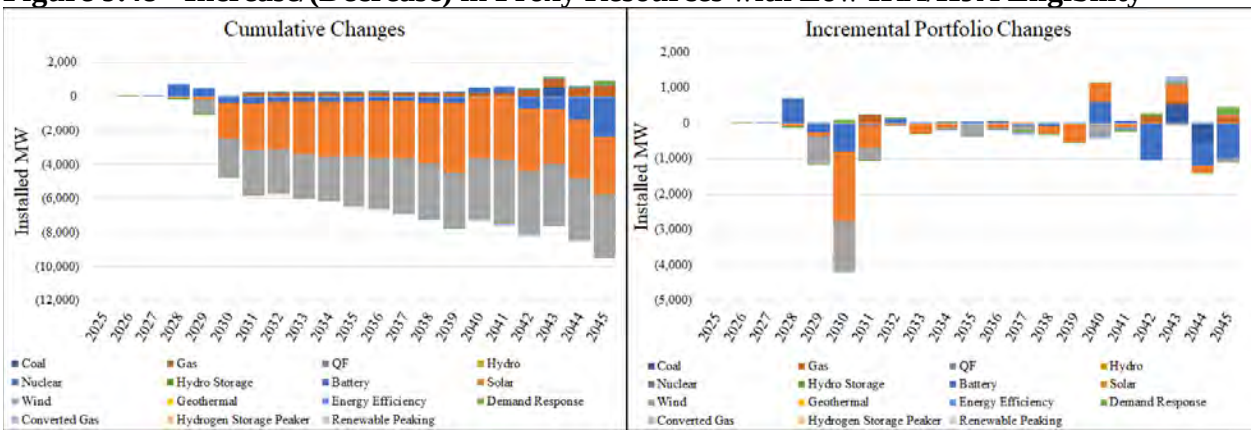



## Low IRA/IIJA Eligibility

The low IRA/IIJA sensitivity evaluates what selections would be made if no resources were ever eligible for IRA or IIJA credits. The purpose of this study is to identify the impact if tax credits were not available to any new resources.

Figure 9.48 shows the cumulative (at left) and incremental (at right) portfolio changes between the low IRA/IIJA portfolio and the preferred portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low IRA/IIJA portfolio includes an additional 627 MW of gas peaking units, and 311 more MW of DSM. The low IRA/IIJA portfolio also includes a reduction of 3,782 MW of wind and 3,366 MW of solar, as well as 2,382 MW of storage. This sensitivity delays the Bridger CCS retirement by one year.

**Figure 9.48 - Increase/(Decrease) in Proxy Resources with Low IRA/IIJA Eligibility**

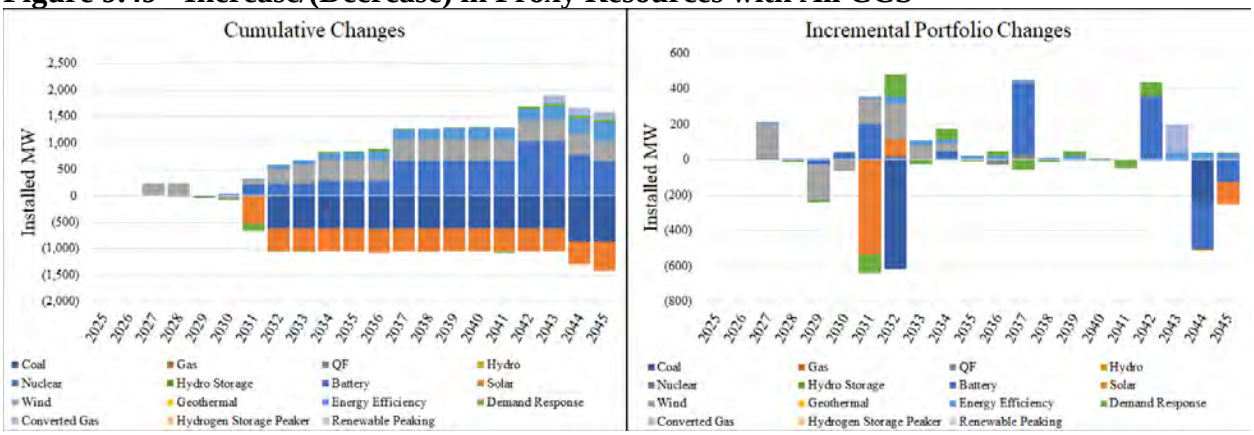


### All CCS

The All CCS sensitivity evaluates what selections would change if it were feasible to convert all units to CCS that would be eligible for conversion. The purpose of this study is to identify the impact of installing up to 8 CCS units.

Figure 9.49 shows the cumulative (at left) and incremental (at right) portfolio changes between the base assumption and allowing all CCS. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In this sensitivity, all eligible units except Wyodak convert to CCS. The lower maximum output means that the sensitivity selects additional resources, including 391 MW of DSM, 397 MW of additional wind and 637 more MW of storage. The only significant reduction is 431 MW of solar.

**Figure 9.49 - Increase/(Decrease) in Proxy Resources with All CCS**

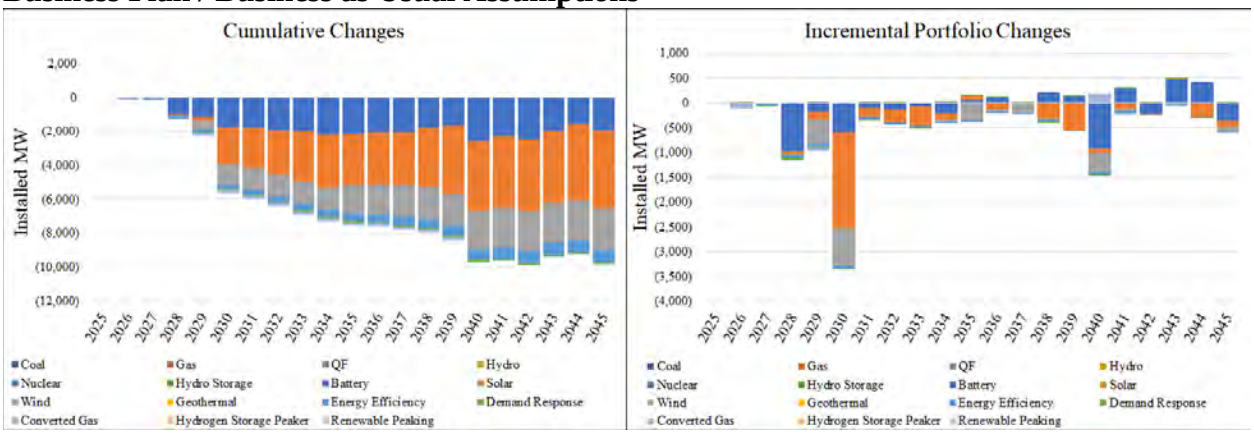



### Business as Usual/Business Plan

The business as usual and business plan sensitivities were able to be covered by the same study. The business-as-usual study requires that coal retires no earlier than in the 2017 IRP unless otherwise mandated to do so by law. The business plan study requires that the first three years of the horizon align with the business plan, and then the model is able to endogenously choose any outcomes. These studies explicitly require operation and resource selection in the absence of any state or federal requirements, and the portfolio must be selected only on the basis of economics.

Figure 9.50 shows the cumulative (at left) and incremental (at right) portfolio changes between be preferred portfolio and a business-as-usual case. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This view selects significantly fewer resources. In total, there are 9,879 fewer MW chosen, and coal continues to remain on the system as in the preferred portfolio. This portfolio selects 2,488 MW less wind, 3,496 MW less utility scale solar, 1,147 MW less small scale solar and a total of 1,903 MW less storage (replacing 100-hour battery with 4-hour battery).

**Figure 9.50 - Increase/(Decrease) in Proxy Resources with Business Plan / Business as Usual Assumptions**




## Washington Scenarios

As described in Chapter 8, in addition to the information provided throughout the 2025 IRP, Washington's CETA legislation mandates three key studies for analysis, in addition to the least-cost, least-risk portfolio developed to meet CETA clean energy standards:

- Alternative Lowest Reasonable Cost
- Maximum Customer Benefit
- Climate Change[9]

This analysis plus additional detail related to Washington requirements is found in Appendix O (Washington Clean Energy Action Plan)

[9] Note: The Washington requirement for a climate change sensitivity, which includes climate change impacts, is met by the incorporation of climate change considerations into all 2025 IRP studies.

# CHAPTER 10 –ACTION PLAN

## CHAPTER HIGHLIGHTS

- The 2025 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio. The action plan has been shaped by changes in the planning environment, ongoing review and validation, and stakeholder feedback.
- PacifiCorp's 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[1]
- The 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide ($CO_2$) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

## Introduction

PacifiCorp's 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

[1] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

## The 2025 IRP Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public input process. Table 10.1 details specific 2025 IRP action items by resource category.

**Table 10.1 – 2025 IRP Action Plan**

| Action Item | 1. Existing Resource Actions |
|---|---|
| 1a | **Colstrip Units 3 and 4:**<br>• PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030. |
| 1b | **Craig Unit 1:**<br>• PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025. |
| 1c | **Naughton Units 1 and 2:**<br>• PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>• PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. |
| 1d | **Carbon Capture and Storage / Low Carbon Portfolio Standard:**<br>• PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. The Company is pursuing a front-end engineering design study as part of compliance with Wyoming's low carbon portfolio standard requirements as a site-specific analysis is needed to better understand the feasibility of the project.[2] |
| 1e | **Regional Haze Compliance:**<br>• Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. |

[2] See Appendix M, stakeholder feedback form #59 (Renewables Northwest).

| | |
|---|---|
| **1f** | **Natrium™ Demonstration Project:**<br>• By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. |
| **1g** | **Ozone Transport Rule Compliance:**<br>• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>• The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments. |
| **1h** | **Natural Gas Emissions Compliance Strategies**<br>• The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030. |
| **1i** | **Federal Greenhouse Gas Emission Compliance:**<br>• EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues. |
| **1j** | **Dave Johnston Units 1 and 2:**<br>• PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029. |

| Action Item | 2. New Resource Actions |
|---|---|
| 2a | **Customer Preference Request for Proposals:**<br>• PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>• Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025. |
| 2b | **2025 All-Source Request for Proposals:**<br>• PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3]<br>• Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process.<br>• Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction. |

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

| Action Item | 3. Transmission Action Items |
|---|---|
| **3a** | **<u>Local Reinforcement Projects</u>**<br>Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids. |
| **3b** | **<u>Gateway West Support</u>**<br>Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. |

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

**Energy Efficiency & Demand Response Targets:**

- PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources.

<table>
<tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2025</td><td>595</td><td>92</td></tr>
<tr><td>2026</td><td>573</td><td>89</td></tr>
<tr><td>2027</td><td>597</td><td>209</td></tr>
<tr><td>2028</td><td>648</td><td>220</td></tr>
</table>

- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2025</td><td>18</td></tr>
<tr><td>2026</td><td>2</td></tr>
<tr><td>2027</td><td>0</td></tr>
<tr><td>2028</td><td>63</td></tr>
</table>

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

| Action Item | 5. Market Purchases |
|---|---|
| 5a | **Market Purchases:**<br>• PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:<br>o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.<br>o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.<br>o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions. |

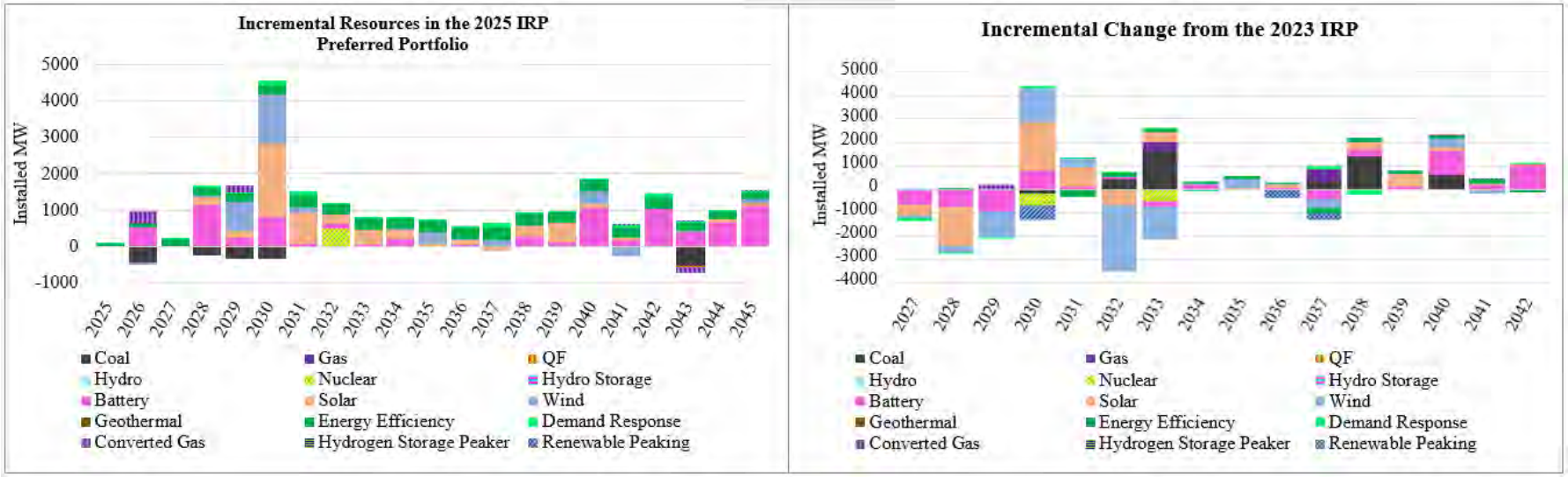
| Action Item | 6. Renewable Energy Credit (REC) Actions |
|---|---|
| 6a | **Renewable Portfolio Standards (RPS):**<br>• PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>• PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed. |
| 6b | **Renewable Energy Credit Sales:**<br>• Maximize the sale of RECs that are not required to meet state RPS compliance obligations. |

## Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the 2025 IRP action plan. The status for all action items from the 2025 IRP is summarized in Table 10.2.

Figure 10.1 below presents two views of incremental resource changes in the 2025 IRP preferred portfolio. The figure at left reports the incremental resource additions from the 2025 IRP preferred portfolio, whereas the figure at right illustrates how these selections differ from the incremental changes in the 2023 IRP preferred portfolio.[6, 7]

**Figure 10.1 – Incremental Resources in the 2025 IRP Preferred Portfolio**




[6] The timeframe presented in these charts shows only years where expansion resources were selected.

[7] These figures support Wyoming Public Service Commission Guideline E, "Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP". A load comparison is provided in Appendix A (Load Forecast), Figure A.1.

**Table** 10.2 – 2023 IRP Action Plan Status Update

| Action Item | 1. Existing Resource Actions | Status |
|---|---|---|
| **1a** | **Colstrip Units 3 and 4:**<br>• PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030. | • PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project. |
| **1b** | **Craig Unit 1:**<br>• PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025. | • PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project. |
| **1c** | **Naughton Units 1 and 2 Gas Conversion:**<br>• PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>• PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. | • PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas.<br>• Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025. |
| **1d** | **Jim Bridger Units 1 and 2 Gas Conversion:**<br>• PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023.<br>• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. | • PacifiCorp received an approval order on December 7, 2023, from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas.<br>• PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023.<br>• Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024. |

| | | |
|---|---|---|
| | | |
| **1e** | **<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>**<br>• PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023.<br>• PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024. | • PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023.<br>• PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200. |
| **1f** | **<u>Regional Haze Compliance:</u>**<br>• Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. | • Utah's first planning period disputes have been resolved.<br>• Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date.<br>• Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits.<br>• PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date. |
| **1g** | **<u>Natrium™ Demonstration Project:</u>** | • PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the |

| | | |
|---|---|---|
| | • PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable.<br>• By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project.<br>• By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders.<br>PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. | Natrium™ project and expects to finalize these arrangements by the end of 2025. |
| **1h** | **<u>Ozone Transport Rule Compliance:</u>**<br>• PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective.<br>• Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023. | • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>• The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. |

| Action Item | 2. New Resource Actions | Status |
|---|---|---|
| 2a | **Customer Preference Request for Proposals:**<br>• PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>• Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window. | PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024. |
| 2b | **2025 All-Source Request for Proposals:**<br>• PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2030.<br>• In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation | The 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term. |

| | | |
|---|---|---|
| | Commission, of PacifiCorp's need for an independent evaluator.<br>• In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions.<br>• In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market.<br>• In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable.<br>• By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.<br>• Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier. | |
| **2c** | **<u>2022 All-Source Request for Proposals:</u>**<br>• In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027.<br>• In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file | • PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities.<br>• EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource |

| | | |
|---|---|---|
| | certificate of public convenience and necessity (CPCN) applications, as applicable, and<br>• By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.<br>• Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier. | procurement needs coming out of the 2022 All-Source Request for Proposals.<br>• PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals. |
| **Action Item** | 3. **Transmission Action Items** | **Status** |
| **3a** | **<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>**<br>• In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service. | The Energy Gateway South transmission project is in-service. |
| **3b** | **<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>**<br>• In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service in Q4 2024<br>• | The Energy Gateway West Sub-Segment D1 transmission project is in-service. |
| **3c** | **<u>Boardman-to-Hemingway (500 kV transmission line):</u>**<br>• Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement.<br>• Continue to participate in the development and negotiations of the construction agreement.<br>• Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date. | PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date. |

| | | |
|---|---|---|
| | • Continue negotiations for plan of service post B2H for parties to the permitting agreement. | |
| **3d** | Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids | Reinforcements have been identified. A final assessment of upgrades is pending signed agreements. |
| **3e** | Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. | PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment. |

| **Action Item** | 4. **Demand-Side Management (DSM) Actions** | **Status** |
|---|---|---|
| **4a** | **<u>Energy Efficiency Targets:</u>**<br>• PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP. | For energy efficiency, PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and achieved 96.2% of the 2024 target, excluding HERs.<br><br>Since the 2023 IRP, PacifiCorp launched demand response programs and expanded offerings within its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023-24 incremental capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs. |

| Year | 1st year Energy Efficiency (GWh) | Annual Capacity (MW) |
|---|---|---|
| 2023 | 543 | 123 |
| 2024 | 559 | 220 |
| 2025 | 568 | 259 |
| 2026 | 628 | 197 |

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- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2023 IRP.

| Year | Annual Incremental Capacity (MW) |
|---|---|
| 2023 | 72 |
| 2024 | 39 |
| 2025 | 152 |
| 2026 | 109 |

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<tr><th>Action Item</th><th>5. Market Purchases</th><th>Status</th></tr>
<tr><td>5a</td><td>

**<u>Market Purchases:</u>**

- Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
- Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
- Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

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Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.

</td></tr>
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| Action Item | 6. **Renewable Energy Credit (REC) Actions** | Status |
|---|---|---|

| | | |
|---|---|---|
| **6a** | **Renewable Portfolio Standards (RPS):**<br>• PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>• As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed. | PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed. |
| **6b** | **Renewable Energy Credit Sales:**<br>• Maximize the sale of RECs that are not required to meet state RPS compliance obligations. | PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations |

# Acquisition Path Analysis

## Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, state and federal environmental policy also influences resource selections in the 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event in Table 10.3, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

## Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[8] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[8] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

**Table 10.3 – Near-term and Long-term Resource Acquisition Paths**

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| Higher sustained load growth | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Load Growth" | • A new load forecast incorporating higher than anticipated load growth increases load relative to the base forecast.<br>• Through 2030, resource additions would be similar to the preferred portfolio with a small amount of additional wind and solar added to the portfolio to meet higher than anticipated loads.<br>• From 2031 through 2034, small amounts of solar, 4-hour battery and DSM resources are added to meet higher than anticipated loads. | • In the long-term acquisition window, slightly fewer incremental resources are required due to additional incremental resources shifting into the near-term window to meet higher than anticipated loads compared to the preferred portfolio. |
| Lower sustained load growth | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Load Growth". | • A new load forecast incorporating lower than anticipated load growth decreases load relative to the base forecast.<br>• In the near-term acquisition window, far fewer incremental resources are required to meet load compared to the preferred portfolio.<br>• Through 2034, significant amounts of wind and solar along with moderate amounts of small-scale solar and 100-hour battery fall out of the portfolio while additional 4-hour battery is added compared to the preferred portfolio.<br>• Fewer incremental transmission options are required to meet fewer incremental resources while the timing of some incremental transmission options is shifted outward compared to the preferred portfolio. | • In the long-term acquisition window, even fewer incremental resources are required due to lower loads compared to the preferred portfolio.<br>• From 2035-2045, significant amounts of wind, solar, small-scale solar and 100-hour battery fall out of the portfolio compared to the preferred portfolio and would not need to be procured. |

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| Higher sustained private generation penetration levels | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Private Generation" | • A new load forecast incorporating higher than anticipated private generation adoption decreases load relative to the base forecast.<br>• In response to high private generation adoption, far fewer incremental resource selections are required in the action plan window compared to the preferred portfolio.<br>• Through 2030, significant amounts of wind, solar, small-scale solar and moderate amounts of 100-hour battery fall out of the preferred portfolio while a significant amount of 4-hour battery is selected.<br>• Through the remainder of the near-term acquisition window, resource additions are similar to the preferred portfolio.<br>• Transmission selections are similar to the preferred portfolio with the location and timing of incremental transmission changing depending on incremental resource selections. | • From 2035-2045, higher private generation results in 2,696 MW of resource additions falling out of the portfolio compared to the preferred portfolio.<br>• On average, far less wind, solar and 100-hour air battery are selected while additional 4-hour battery is selected in similar amounts compared to the preferred portfolio. |
| Lower sustained private generation penetration levels | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Private Generation" | • A new load forecast incorporating lower than anticipated private generation adoption increases load relative to the base forecast.<br>• To counteract low private generation adoption, minimal additional resources are required relative to the preferred portfolio through 2029.<br>• From 2030 through 2034, moderate amounts of wind and solar are added to what is selected in the preferred portfolio. | • In the long-term resource acquisition window, resource selections are similar to the preferred portfolio as lower private generation levels cause incremental resource builds in the near-term acquisition window.<br>• 156 MW of Naughton gas conversion would remain online compared to retiring in 2043 in the preferred portfolio. |

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| Higher than expected large-metered load growth | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Large Metered Load Growth" | • A new load forecast incorporating higher than anticipated large-metered load growth beginning in 2027 increases load relative to the base forecast.<br>• High large-metered load growth results in significant resource additions compared to the preferred portfolio, including significant resource additions in the near-term acquisition window.<br>• By 2028, nearly 10,000 MW of additional resources are selected compared to the preferred portfolio including significant amounts of wind, solar, small-scale solar, 4-hour battery and a moderate amount of 8-hour battery.<br>• By the end of 2034, a significant amount of new gas is added to the portfolio, along with nearly 4,500 MW of additional incremental renewable resources.<br>• Significant transmission investment would be required to serve new resource additions. | • From 2035-2045, significant additional resources are required compared to the preferred portfolio including more than 1,000 MW of new gas and 5,000 MW of new renewables. |
| Changes to IRA/IIJA result in lower-than-expected renewable costs | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low-Cost Renewables" | • High adoption of the IRA/IIJA resulting in lower-than-expected new renewable resource costs would result in significantly more incremental renewable resource additions than selected in the preferred portfolio.<br>• Significant incremental wind, solar and 4-hour battery additions would result in lower thermal output and less 100-hour battery storage additions.<br>• Significant transmission investment would be required to serve new resource additions. | • From 2035-20445, significant additional incremental renewable resources would be built along with more incremental transmission.<br>• Thermal resources would run at lower capacity factors with some thermal capacity retiring in the long-term acquisition window. |

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| Changes to IRA/IIJA result in higher-than-expected renewable costs | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low PTC/ITC eligibility" | • In the absence of tax credits from the IRA/IIJA resulting in higher-than-expected renewable resource costs, significant amounts of incremental renewable resource additions would fall out of the portfolio compared to the preferred portfolio.<br>• By 2030, significant wind, solar, small-scale solar and 100-hour iron battery would fall out from the portfolio.<br>• By the end of 2034, significant additional incremental renewable capacity falls out of the portfolio while some new gas is selected.<br>• If renewable resources become more expensive in the absence of IRA/IIJA benefits, very little capacity would be needed to replace renewable capacity as thermal resources would run at higher capacity factors to meet load obligations. | • In the long-term acquisition window, additional new gas is built along with a small amount of gas peaking to replace lost renewables from the preferred portfolio.<br>• Existing thermal resources would remain online past retirement dates selected in the preferred portfolio to continue providing energy and capacity. |
| No legislation under consideration is adopted and state environmental requirements impacting thermal plants are unwound | Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Business as Usual" (also called the Wyoming Reference Case). | • With only load requirements to meet (no other federal or state requirements), far fewer resources are selected compared to the preferred portfolio as existing thermal resources are able to run at higher capacity factors and less capacity and energy is needed on the system.<br>• In the near-term acquisition window, significantly fewer MW are selected compared to the preferred portfolio, including less wind, solar, small-scale solar, 4-hour battery and 100-hour battery.<br>• With far fewer new resources compared to the preferred portfolio, "business as usual" would require significantly fewer incremental transmission interconnect MW in the near-term acquisition window. | • From 2035-2045, significantly fewer MW are selected compared to the preferred portfolio including less wind, solar, small-scale solar and 100-hour battery.<br>• Additional 4-hour battery is added from 2035 through 2045 compared to the preferred portfolio, revealing that in a "business as usual" scenario, 4-hour batteries remain valuable new resource options in the absence of other new renewables. |
| Legislation forces all coal to retire or gas convert by 2032 | Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Coal 2032" | • With all coal units forced to retire or gas convert by 1/1/2032, 2,679 MW of nameplate capacity would convert to natural gas in 2030. Jim Bridger units 3 and 4 were assumed to not be allowed to install CCS, and in this case, units 3 and 4 would convert to natural gas in 2030 instead of retiring.<br>• By 1/1/2032, 686 MW of coal retires.<br>• Significant additional incremental renewable resources and are added to the portfolio including wind, solar, 4-hour battery and 100-hour battery within the near-term acquisition window. | • In the long-term acquisition window resource additions are similar to the preferred portfolio. |

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| No Natrium™ Advanced Nuclear Demonstration Project in 2032, and no other nuclear projects | Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Nuclear" | • Without the 500 MW Natrium™ demonstration project in 2032, moderate amounts of renewable resources are added to the portfolio by 2032.<br>• In 2033 and 2034, additional incremental renewable resources are added to the portfolio. | • While the type, timing and location of resources change, the amount of incremental resource additions in the long-term acquisition window without Natrium™ is similar to the preferred portfolio.<br>• Batteries and other renewables would fall out of the portfolio in 2041 through 2045 as incremental amounts of these resources are built earlier to replace Natrium™.<br>• 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion. |
| Technologies such as nuclear, hydrogen storage, 100-hour battery storage and biodiesel peaking do not become commercially viable | Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Forward Technology" | • Without nuclear, hydrogen storage, 100-hour battery or biodiesel peaking, nuclear and 100-hour battery selected in the preferred portfolio are replaced by a significant amount of 4-hour battery and moderate amounts of wind and solar.<br>• In the near-term acquisition window, the capacity of future technology that falls out of the portfolio is greater than the capacity of incremental resources needed to replace the lost capacity. | • While the type, timing and location of resources change as is required by the absence of nuclear and 100-hour battery, the amount of incremental resource additions in the long-term acquisition window is similar to the preferred portfolio.<br>• 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion. |

| Trigger Event | Planning Scenario(s) | Near-Term Resource Acquisition Strategy (2025-2034) | Long Term Resource Acquisition Strategy (2035-2045) |
|---|---|---|---|
| Legislation requires the Hunter plant to retire no later than 1/1/2030 | Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "Hunter Retire" | • By 1/1/2030, 1,158 MW of nameplate coal capacity retires at Hunter.<br>• To replace the lost Hunter capacity, by 2030, moderate amounts of wind and solar would be added to the portfolio, including solar at Hunter. Additionally, a significant amount of 4-hour battery and moderate amount of 100-hour battery would be added to the portfolio. | • From 2035-2045, moderate amounts of incremental resource additions would be added to the portfolio, including new gas.<br>• In 2043, 156 MW of nameplate capacity at Naughton 1 running as gas remains online through the end of the planning horizon instead of retiring as it does in the preferred portfolio. |
| No CCS available at Jim Bridger in 2030 | Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No CCS" | • Incremental resource selections with Jim Bridger CCS unavailable are similar to the preferred portfolio with slight changes in the location and timing of incremental resources.<br>• By 1/1/2030, 174 MW of nameplate capacity remains available at Jim Bridger without the installation of CCS.<br>• Moderate amounts of wind and solar, some of which is sited at Jim Bridger, falls out of the portfolio, along with some 4-hour battery. | • From 2039-2045 fewer 4-hour battery resources are selected.<br>• In 2043, 247 MW of Naughton gas conversion retires without CCS in the portfolio. |

## Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable resilient grid operations and statutory compliance. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, there may be insufficient potential resource development deliverable to the jurisdiction with resource need, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

As the range of events is unknowable, these potential impacts are represented by broad sensitivity studies such as those which raise or lower resource availability (such as natrium, carbon capture, coal, offshore wind) and competition for resources (load, distributed generation, IRA adoption, DSM). In addition, IRP resource potential availability is informed by an assessment of publicly available data derived from the cluster study process.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

## IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.

- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Consequently, please refer to the 2025 IRP preferred portfolio as described in Chapter 9.

## Resource Procurement Strategy

To acquire resources outlined in the 2025 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates if jurisdictional need is warranted. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs to include but not limited to load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2025 IRP action plan.

### Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

### Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

### Demand-Side Management[9]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings and has continued Wattsmart outreach and communications. Educating customers regarding

[9] Class 1 DSM is most commonly referred to as “demand response” in the 2023 IRP; Class 2 DSM is most commonly referred to as “energy efficiency”. Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

### Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in June 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by December 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is discussed in Appendix P (Oregon Clean Energy Update) and will be further addressed in PacifiCorp's 2025 Oregon Clean Energy Plan.

## Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. The level of debt imputation associated with long-term contracts will have an impact on PacifiCorp's credit ratios and credit rating.

## Managing Carbon Risk for Existing Plants

$CO_2$ reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower $CO_2$ emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by $CO_2$ reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a $CO_2$ tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as $CO_2$ capture with sequestration. As mentioned above, plant $CO_2$ emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

## Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

### Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes

recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

## Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

### Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

### Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

## Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

### Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not fully reflected in rates and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

### Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

### Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission

infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of $CO_2$ policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

# CHAPTER 11 –UTAH EXECUTIVE SUMMARY

**ORDER ISSUED IN DOCKET NO. 23-035-10**

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to these three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

## Maintaining customer focus

The Utah Integrated Resource Plan (IRP) is a roadmap for continual progress to safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

### Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.
- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in the fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

- The following resources are added in the Utah 2025 IRP:
  - 6,379 megawatts of new wind resources
  - 7,668 megawatts of storage resources, including four-hour, eight-hour, and 100-hour durations
  - 5,492 megawatts of new solar resources
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

**Customer Programs**

- 5,149 megawatts of capacity saved through energy efficiency programs
- 1,052 megawatts of capacity saved through direct load control programs

**Transmission**

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington
- 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon
- New transmission, including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon
- A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2)
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

## Changes to our Portfolio

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Continue to evaluate coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

## PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are allocated to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[2] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements are represented:

- Utah, Idaho, Wyoming, and California (UIWC)[3]
  - Cost-effective resources
  - Includes WRAP compliance constraints for UIWC load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Includes WRAP compliance constraints for Oregon load
  - Includes small-scale renewable capacity requirement
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and only allocated to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a

[2] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[3] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of the draft necessitated coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off, PacifiCorp hosted stakeholders in seven online public input meetings. An additional two meetings were held with stakeholders after the distribution of the draft. Analysis conducted aligned to those meetings, after the Draft 2025 IRP filing, informs Chapters 1 through 10 and Appendices A through Z, which comprise the majority of this document.

Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 11.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action

plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

**Figure 11.1 – Key Elements of PacifiCorp's 2025 IRP Approach**



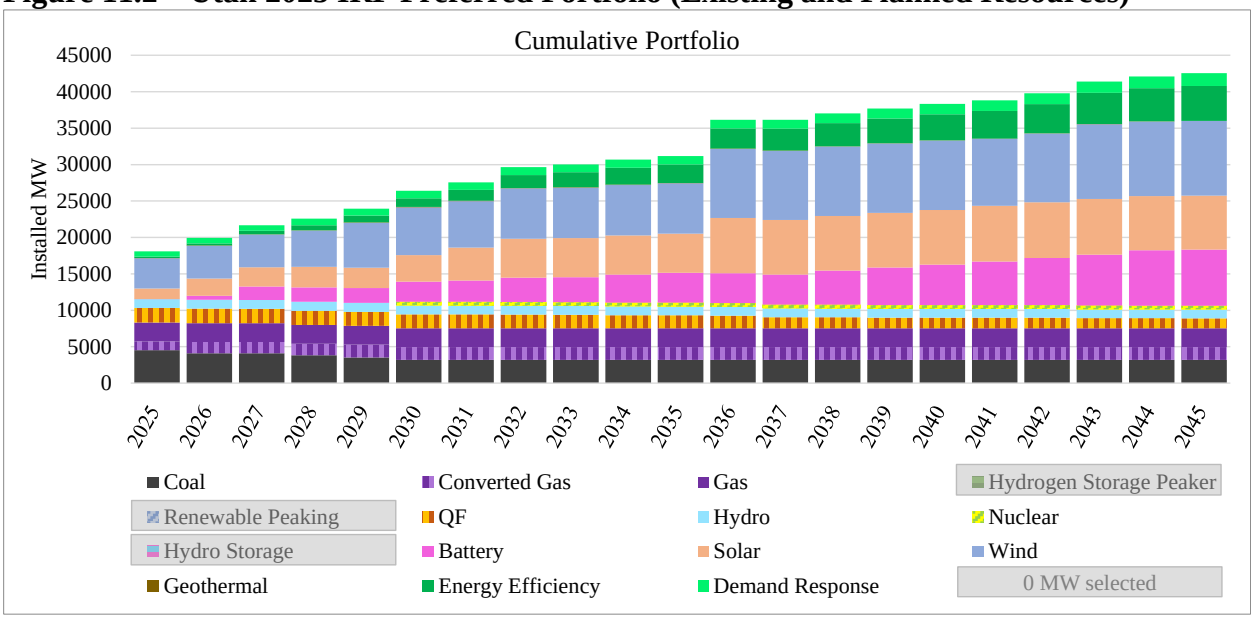

## Preferred Portfolio Highlights

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in Chapters 2 through 8, and the Appendices that follow. Figure 11.2 shows that PacifiCorp's Utah 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and non-emitting peaking resources facilitated by incremental transmission investments.

The Utah 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium$^{TM}$ demonstration project, anticipated to achieve online status by the end of 2030. By the end of 2032, the preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 20-year planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

**Figure 11.2 – Utah 2025 IRP Preferred Portfolio (Existing and Planned Resources)***




* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah, known as Energy Gateway South 2, planned to come online in 2036. Smaller upgrades increase transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 11.1 summarizes the incremental transmission projects in the Utah 2025 IRP preferred portfolio. Note, at this time, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

**Table 11.1 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]**

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| **2026** | Rebuild existing Cameron - Sigurd 138 kV | 250 | 250 | 250 | 30 | 100% | Utah South | Wasatch Front |
| **2027** | Cluster 1 Area 11 - Willamette Valley | 0 | 0 | 199 | 13 | 100% | n/a | n/a |
| | Serial queue - Central Oregon | 0 | 0 | 152 | 3 | 100% | n/a | n/a |
| **2028** | Cluster 2 Area 23 - Willamette Valley | 0 | 0 | 393 | 2 | 100% | n/a | n/a |
| **2030** | Cluster 1/2/3 - Walla Walla | 0 | 0 | 628 | 66 | 100% | n/a | n/a |
| **2031** | Cluster 1/2/3 - Walla Walla | 0 | 0 | 393 | 348 | 100% | n/a | n/a |
| | Walla Walla - Wine Country 230 kV | 400 | 400 | 400 | 145 | 100% | n/a | n/a |
| **2032** | Cluster 1 Area 14 - Summer Lake | 400 | 400 | 400 | 120 | 100% | Summer Lake | Hemingway |
| | Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV | 450 | 450 | 450 | 413 | 100% | Willamette Valley | Central OR |
| **2036** | Gateway South 2: Aeolus Clover #2 500 kV | 1,500 | 1,500 | 1,990 | 1,810 | 100% | Wyoming East | Clover |
| | Huntington – Clover 345 kV | 800 | 800 | 800 | 264 | 100% | Utah South | Wasatch Front |
| | Spanish Fork - Mercer 345 kV | 300 | 300 | 300 | 153 | 100% | Utah South | Wasatch Front |
| | West Cedar - Three Peaks 138 kV | 200 | 200 | 200 | 14 | 100% | Utah South | Wasatch Front |
| | S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV | 1,500 | 1,500 | 665 | 1,117 | 100% | Willamette Valley | Southern OR |
| **2041** | Serial through Cluster 1 Area 13 - Southern Oregon | 0 | 0 | 231 | 52 | 100% | n/a | n/a |
| **Grand Total** | | **5,800** | **5,800** | **7,451** | **4,551** | | | |

[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

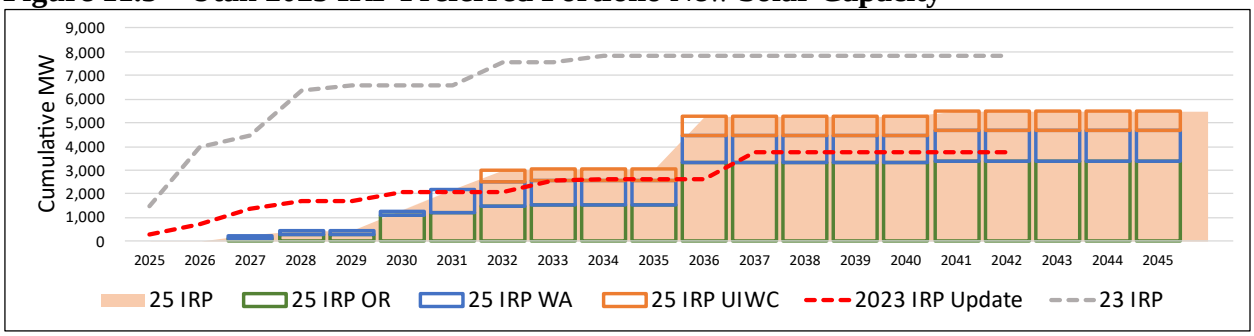
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

In Chapter 12 – Utah Model Results, a sensitivity analysis evaluates the impacts of significant new loads coming online in the 2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

## New Solar Resources

The Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and 5,492 MW by the end of 2045, as shown in Figure 11.3.

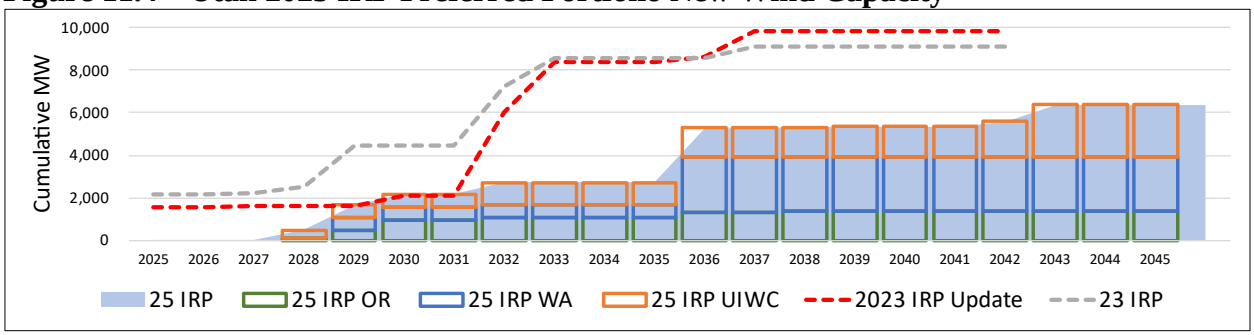
**Figure 11.3 – Utah 2025 IRP Preferred Portfolio New Solar Capacity**



## New Wind Resources

As shown in Figure 11.4, PacifiCorp's 2025 IRP Utah preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379MW of cumulative new wind by the end of 2045.

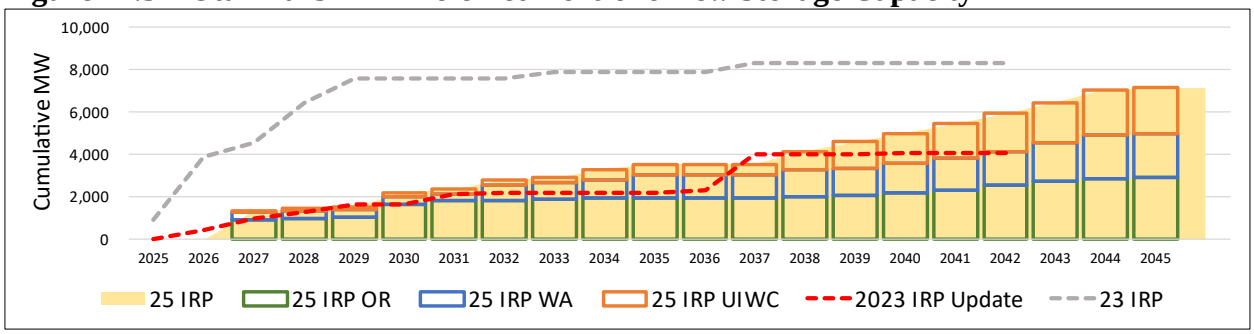
**Figure 11.4 – Utah 2025 IRP Preferred Portfolio New Wind Capacity**




## New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 11.5. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4-hour and 8-hour lithium-ion storage. By year-end 2030, the Utah 2025 IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

**Figure 11.5 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1,2]**

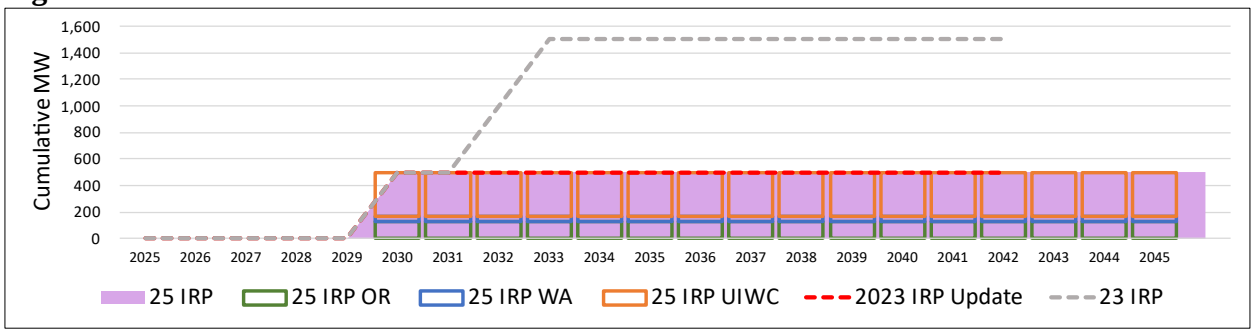



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

## New Nuclear Resources

The Utah 2025 IRP preferred portfolio includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 11.6, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the end of 2030.

**Figure 11.6 – Utah 2025 IRP Preferred Portfolio New Nuclear**




## Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers, who are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits.

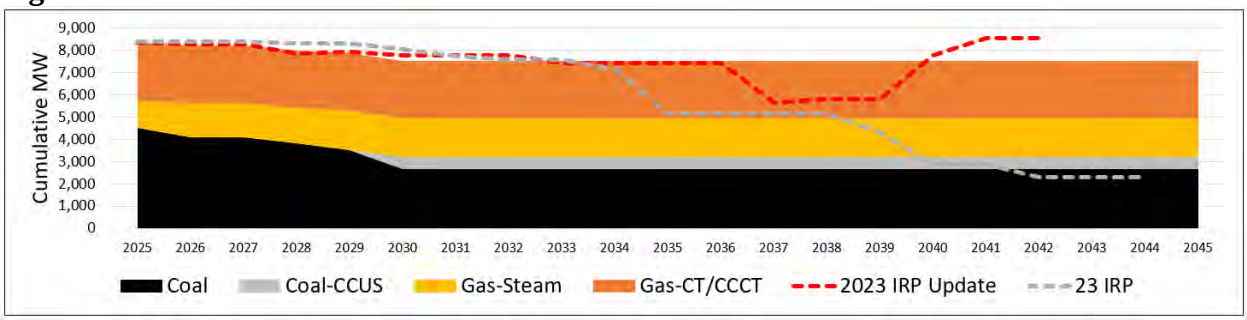
- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
    - 678 megawatts of energy efficiency between 2025 and 2028
    - 213 megawatts of demand response between 2025 and 2028

## Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled

the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 11.7, the Utah 2025 IRP preferred portfolio converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386 MW of minority-owned coal, and also retires 220 MW of majority-owned coal at Dave Johnston by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

**Figure 11.7 – Utah 2025 IRP Preferred Portfolio Thermal Resources**




A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 11.2. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

## Table 11.2 – 2025 IRP Coal Resource Results Summary

| Majority-Owned Coal | | | |
|---|---|---|---|
| Unit | Utah 2025 IRP Retirement Year | | 2023 IRP Retirement Year |
| | Selected w/o 111(d) Regulation | Selected w/ 111(d) Regulation | As Selected |
| Dave Johnston 1 & 2 | Not retired (Gas conversion 2029) | No change | 2028 |
| Dave Johnston 3 | 2027 (Clean air compliance) | No change | 2027 (Clean air compliance) |
| Dave Johnston 4 | Not retired | Not retired (Gas conversion 2030) | 2039 |
| Hunter 1 | Not retired | Not retired (Alt. fuel conv. 2030) | 2031 |
| Hunter 2 & 3 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Huntington 1 & 2 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Jim Bridger 1 & 2 | Not retired (Gas conversion 2024) | No change | 7 (Gas conversion 2024) |
| Jim Bridger 3 & 4 | Not retired (CCS conversion 2030) | No change | 2037 (Gas conversion 2030) |
| Naughton 1 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Naughton 2 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Wyodak | Not retired | 2032 | 2039 |

| Minority-Owned Coal | | |
|---|---|---|
| Unit | 2025 IRP Retirement Year | 2023 IRP Retirement Year |
| | As Input | As Input |
| Colstrip 3 | 2025 (Transfer capacity to unit 4) | 2025 (Transfer capacity to unit 4) |
| Colstrip 4 | 2029 (PacifiCorp exit) | 2029 (PacifiCorp exit) |
| Craig 1 | 2025 (Assumed end of life) | 2025 (Assumed end of life) |
| Craig 2 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 1 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 2 | 2027 (Assumed end of life) | 2027 (Assumed end of life) |

## Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 11.3 details specific 2025 IRP action items by resource category.

**Table 11.3 – 2025 IRP Action Plan**

| Action Item | 1. Existing Resource Actions |
|---|---|
| 1a | **Colstrip Units 3 and 4:**<br>• PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030. |
| 1b | **Craig Unit 1:**<br>• PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the Utah 2025 IRP preferred portfolio target exit date of December 31, 2025. |
| 1c | **Naughton Units 1 and 2:**<br>• PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>• PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. |
| 1d | **Carbon Capture and Storage / Low Carbon Portfolio Standard:**<br>• PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. |
| 1e | **Regional Haze Compliance:**<br>• Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. |

| Action Item | 1. Existing Actions (continued) |
|---|---|
| 1f | **Natrium™ Demonstration Project:**<br>• By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. |
| 1g | **Ozone Transport Rule Compliance:**<br>• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>• The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments. |
| 1h | **Natural Gas Emissions Compliance Strategies**<br>• The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030. |
| 1i | **Federal Greenhouse Gas Emission Compliance:**<br>• EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues. |
| 1j | **Dave Johnston Units 1 and 2:**<br>• PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029. |

| Action Item | 2. New Resource Actions |
|---|---|
| 2a | **Customer Preference Request for Proposals:**<br>• PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer needs. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>• Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025. |
| 2b | **2025 All-Source Request for Proposals:**<br>• PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[4]<br>• In light of the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction. |

| Action Item | 3. Transmission Action Items |
|---|---|
| 3a | **Local Reinforcement Projects**<br>Initiate local reinforcement projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids. |
| 3b | **Gateway West Support**<br>Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. |

[4] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

| Action Item | 4. Demand-Side Management (DSM) Actions |
|---|---|
| 4a | **Energy Efficiency Targets:**<br>• PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.<br>• PacifiCorp will pursue cost-effective energy efficiency resources.<br>• PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year. |
| **Action Item** | **5. Market Purchases** |
| 5a | **Market Purchases:**<br>• PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:<br>o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.<br>o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.<br>o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions. |

| Action Item | 6. Renewable Energy Credit (REC) Actions |
|---|---|
| 6a | **Renewable Portfolio Standards (RPS):**<br>• PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>• PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed. |
| 6b | **Renewable Energy Credit Sales:**<br>• Maximize the sale of RECs that are not required to meet state RPS compliance obligations. |

# CHAPTER 12 – UTAH MODEL RESULTS

## ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

## CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The Utah 2025 IRP preferred portfolio includes resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The Utah 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that a forthcoming RFP as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The Utah 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind, 2,308 MW of which is small-scale, and 5,492 MW of new solar.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, a new 230 kV line from the Willamette Valley to Central Oregon, and Gateway

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

South 2, a new 500 kV line from the Aeolus substation in Wyoming to the Clover substation in Utah.

- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation are converted to natural gas where the option is available.

- In the 2025 IRP, four factors drive a reduction in $CO_2$ emissions after 2025. These factors are: retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities, and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially as a result of renewable resource additions, but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

## Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the Utah 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios supporting Washington's Clean Energy Transformation Act (CETA)[2] and discussion of Oregon's compliance position in the Utah preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

## Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 12.1 below shows the various phases of the Utah, Idaho, Wyoming and California (UIWC) MN fully initial jurisdictional run to demonstrate a snapshot of how iterative jurisdictional portfolios were

[2] Volume II, Appendix O provides additional detail relevant to Washington requirements.

evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase is selected for integration. In Table 12.1, phase 5 was selected as the UIWC initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $21,842 million, and the stream of unserved energy costs that led to a total cost of $1 million which had no unserved energy after 2027. No other phase had both a lower PVRR and a lower unserved energy cost. Other phases which were considered were phase 1, phase 3 and phase 9, however the higher PVRR of phases 3 and 9, and the fact that phase 1 had small amounts of unserved energy through the 21-year study horizon led to phase 5 being selected.

**Table 12.1 – Iterative phases of Utah, Idaho, Wyoming and California MN portfolio**

| Phase | Jurisdiction | Price-Policy | 21 Year PVRR | Unserved Energy Cost |
|---|---|---|---|---|
| 0 | UIWC | Medium Gas, No CO2 | 20,628 | 14 |
| 1 | UIWC | Medium Gas, No CO2 | 21,587 | 1 |
| 2 | UIWC | Medium Gas, No CO2 | 21,212 | 10 |
| 3 | UIWC | Medium Gas, No CO2 | 21,848 | 1 |
| 4 | UIWC | Medium Gas, No CO2 | 22,036 | 22 |
| 5 | UIWC | Medium Gas, No CO2 | 21,842 | 1 |
| 6 | UIWC | Medium Gas, No CO2 | 20,942 | 29 |
| 7 | UIWC | Medium Gas, No CO2 | 21,999 | 1 |
| 8 | UIWC | Medium Gas, No CO2 | 21,128 | 30 |
| 9 | UIWC | Medium Gas, No CO2 | 21,932 | 1 |
| 10 | UIWC | Medium Gas, No CO2 | 21,145 | 25 |
| 11 | UIWC | Medium Gas, No CO2 | 22,143 | 1 |
| 12 | UIWC | Medium Gas, No CO2 | 21,157 | 19 |
| 13 | UIWC | Medium Gas, No CO2 | 22,216 | 1 |
| 14 | UIWC | Medium Gas, No CO2 | 20,526 | 18 |
| 15 | UIWC | Medium Gas, No CO2 | 22,503 | 3 |

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal $CO_2$ policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy $CO_2$ policy assumptions, resulting in uniquely optimized combinations of resources, transmission and thermal retirement options.

As discussed in Chapter 8 (Modeling and Portfolio Evaluation), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and Utah preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

## Jurisdictional Shares of the Preferred Portfolio

Table 12.2 through Table 12.4 present each jurisdiction's assumed *share* of the total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

## Table 12.2 – Oregon Share

| OR Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity (MW) | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Expansion Options | | | | | | | | | | | | | | | | | | | | | | |
| DSM - Energy Efficiency | - | 55 | 79 | 81 | 84 | 87 | 93 | 94 | 94 | 93 | 93 | 83 | 89 | 89 | 87 | 90 | 91 | 101 | 169 | 160 | 151 | 1,966 |
| DSM - Demand Response | - | 24 | 7 | 38 | 6 | 60 | 7 | 4 | 2 | 3 | 1 | - | 53 | 51 | 3 | 21 | 30 | 3 | 3 | 37 | 7 | 361 |
| Nuclear | - | - | - | - | - | 130 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 130 |
| Renewable - Utility Wind | - | - | - | 83 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 83 |
| Renewable - Small Scale Wind | - | - | - | - | 380 | 505 | 4 | 85 | 0 | - | - | 246 | 4 | 37 | 5 | - | - | - | - | - | - | 1,267 |
| Renewable - Utility Solar | - | - | 109 | 165 | - | 848 | 102 | 579 | 45 | 4 | - | 1,888 | 1 | - | - | - | - | - | - | - | - | 3,741 |
| Renewable - Battery | - | 132 | 940 | 7 | - | 10 | - | 2 | 3 | 1 | 1 | - | - | 2 | 2 | 3 | 7 | 234 | 1 | 1 | 1 | 1,346 |
| Renewable - Battery (Long Duration) | - | - | 1 | 26 | 62 | 590 | 166 | 11 | 93 | 44 | 17 | - | - | 35 | 53 | 100 | 140 | - | 198 | 139 | 44 | 1,720 |

## Table 12.3 – Washington Share

| WA Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity (MW) | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Expansion Options | | | | | | | | | | | | | | | | | | | | | | |
| DSM - Energy Efficiency | - | 14 | 13 | 14 | 15 | 15 | 16 | 16 | 16 | 15 | 15 | 13 | 12 | 10 | 9 | 8 | 7 | 7 | 7 | 6 | 4 | 233 |
| DSM - Demand Response | - | 15 | 4 | 8 | 1 | - | 6 | 1 | - | 1 | 0 | - | 0 | 11 | 1 | 12 | 1 | 1 | 1 | 3 | 1 | 67 |
| Nuclear | - | - | - | - | - | 32 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 32 |
| Renewable - Utility Wind | - | - | - | - | 594 | - | - | 0 | - | - | 3 | 1,988 | - | - | - | - | - | - | - | - | - | 2,585 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 5 | - | - | - | - | - | - | 5 |
| Renewable - Utility Solar | - | - | 136 | 17 | - | - | 794 | 0 | 4 | 0 | - | - | - | - | - | - | 237 | - | - | - | - | 1,189 |
| Renewable - Battery | - | 37 | 354 | 6 | - | - | - | 400 | - | 93 | 173 | - | - | 247 | 4 | 78 | 95 | 58 | 192 | 274 | 9 | 2,020 |
| Renewable - Battery (Long Duration) | - | - | - | - | - | - | - | 11 | - | - | 4 | - | - | 7 | 8 | 12 | 5 | - | 31 | 6 | - | 83 |

**Table 12.4 – Utah, Idaho, Wyoming and California Share**

| UIWC Shares by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity (MW) | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| Expansion Options | | | | | | | | | | | | | | | | | | | | | | |
| DSM - Energy Efficiency | 50 | 57 | 145 | 167 | 172 | 182 | 233 | 219 | 197 | 174 | 157 | 159 | 149 | 134 | 123 | 109 | 102 | 123 | 107 | 103 | 84 | 2,947 |
| DSM - Demand Response | 14 | 1 | 1 | 98 | 26 | 21 | - | 31 | - | 42 | 23 | 12 | 13 | 13 | 38 | 18 | 16 | 30 | 68 | 22 | 135 | 622 |
| Nuclear | - | - | - | - | - | 338 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 338 |
| Renewable - Utility Wind | - | - | - | 403 | 211 | - | - | 451 | - | - | - | 338 | - | - | - | - | - | - | - | - | - | 1,403 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 236 | 802 | - | - | 1,039 |
| Renewable - Utility Solar | - | - | - | - | - | - | - | 226 | - | 0 | - | 333 | 3 | - | - | - | - | - | - | - | - | 563 |
| Renewable - Battery | - | 352 | 2 | 103 | - | 30 | - | 14 | - | 224 | 2 | - | 11 | 4 | 4 | - | 4 | 197 | 63 | 4 | 4 | 1,018 |
| Renewable - Battery (Long Duration) | - | - | - | - | - | 65 | - | - | - | 44 | 46 | - | - | 285 | 405 | 200 | 180 | - | 35 | 187 | 35 | 1,481 |

## Full Jurisdictional Portfolios

Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration.

The following portfolios shown in Table 12.5 through Table 12.7 report the entirety of portfolio selections made when planning for the entire system, not just the jurisdictional share, according to each jurisdiction's constraints.

# Table 12.5 – Oregon Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 89 | 89 | 233 | 253 | 261 | 275 | 325 | 322 | 302 | 277 | 260 | 248 | 250 | 233 | 219 | 208 | 201 | 232 | 283 | 269 | 235 | 5,064 |
| DSM - Demand Response | 18 | 25 | 7 | 38 | 86 | 60 | 7 | 4 | 2 | 3 | 1 | - | 255 | 85 | 47 | 46 | 46 | 27 | 79 | 61 | 43 | 940 |
| Renewable - Wind | - | - | 222 | 166 | - | 594 | - | - | - | - | 3 | - | 31 | 256 | - | - | - | - | - | - | - | 1,272 |
| Renewable - Small Scale Wind | - | - | - | - | 380 | 505 | 4 | 85 | - | - | - | 246 | 4 | 37 | 9 | - | - | - | - | - | - | 1,270 |
| Renewable - Utility Solar | - | - | 109 | 165 | - | 848 | 102 | 807 | 45 | 4 | 2 | 2,221 | 4 | - | - | - | - | - | - | - | - | 4,307 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery | - | 520 | 1,091 | 10 | - | 19 | 5 | 3 | 25 | 3 | 4 | - | - | 146 | 6 | 7 | 16 | 504 | 67 | 6 | 6 | 2,438 |
| Renewable - Battery (Long Duration) | - | - | 1 | 26 | 62 | 655 | 166 | 22 | 93 | 88 | 67 | - | - | 130 | 174 | 634 | 381 | 97 | 277 | 332 | 80 | 3,285 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | (20) |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **107** | **487** | **1,663** | **403** | **666** | **3,035** | **400** | **1,243** | **467** | **372** | **337** | **2,715** | **444** | **855** | **455** | **895** | **246** | **860** | **659** | **435** | **344** | |

## Table 12.6 – Washington Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| **Resource** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | 221 | - | - | - | - | - | - | - | - | - | - | - | 179 | - | - | - | - | 400 |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 89 | 89 | 214 | 236 | 243 | 252 | 326 | 322 | 300 | 283 | 265 | 258 | 260 | 243 | 229 | 217 | 210 | 230 | 285 | 271 | 236 | 5,058 |
| DSM - Demand Response | 18 | 17 | 4 | 8 | 37 | - | 185 | 35 | - | 54 | 57 | - | 26 | 44 | 42 | 52 | 24 | 45 | 30 | 78 | 40 | 796 |
| Renewable - Wind | - | - | 1,008 | - | 594 | - | - | 17 | - | - | 3 | 1,990 | 130 | - | - | - | - | - | - | - | - | 3,742 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 121 | 157 | - | - | - | 194 | 660 | 1,132 |
| Renewable - Utility Solar | - | - | 136 | 17 | - | - | 794 | 630 | 4 | 1 | - | - | - | 406 | - | - | 237 | - | - | - | - | 2,225 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery | - | 520 | 490 | 6 | - | - | 5 | 747 | - | 296 | 196 | - | - | 269 | 28 | 471 | 177 | 152 | 347 | 285 | 15 | 4,004 |
| Renewable - Battery (Long Duration) | - | - | - | - | - | - | - | 25 | - | - | 132 | - | - | 121 | 139 | 224 | 92 | 395 | 107 | 108 | - | 1,343 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (1,030) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,592) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 892 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | (20) |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | **107** | **479** | **1,852** | **12** | **972** | **331** | **1,101** | **1,776** | **304** | **631** | **653** | **2,248** | **316** | **1,051** | **559** | **1,121** | **521** | **822** | **722** | **703** | **931** | |

## Table 12.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 89 | 89 | 203 | 247 | 256 | 271 | 331 | 319 | 298 | 273 | 255 | 259 | 250 | 233 | 220 | 208 | 207 | 232 | 283 | 271 | 239 | 5,033 |
| DSM - Demand Response | 18 | 1 | - | 157 | 40 | 33 | - | 46 | - | 86 | 29 | 27 | 17 | 17 | 47 | 47 | 46 | 33 | 74 | 61 | 144 | 923 |
| Renewable - Wind | - | - | - | 486 | 211 | - | - | 1,045 | - | - | - | 340 | - | - | - | - | - | - | - | - | - | 2,082 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 143 | 390 | 802 | - | - | 1,335 |
| Renewable - Utility Solar | - | - | - | - | - | - | - | 1,675 | - | 4 | - | 670 | 4 | - | - | - | - | - | - | - | - | 2,353 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery | - | 520 | 4 | 444 | 355 | 134 | - | 389 | - | 232 | 4 | - | 11 | 6 | 6 | - | 14 | 462 | 65 | 6 | 6 | 2,658 |
| Renewable - Battery (Long Duration) | - | - | - | - | - | 130 | - | - | - | 100 | 78 | 368 | 383 | 359 | 466 | 312 | 325 | - | 51 | 332 | 70 | 2,974 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | - | (50) |
| Expire - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | (20) |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **107** | **463** | **207** | **1,079** | **739** | **647** | **122** | **3,474** | **298** | **692** | **366** | **1,664** | **565** | **583** | **739** | **567** | **337** | **1,117** | **1,228** | **437** | **439** | |

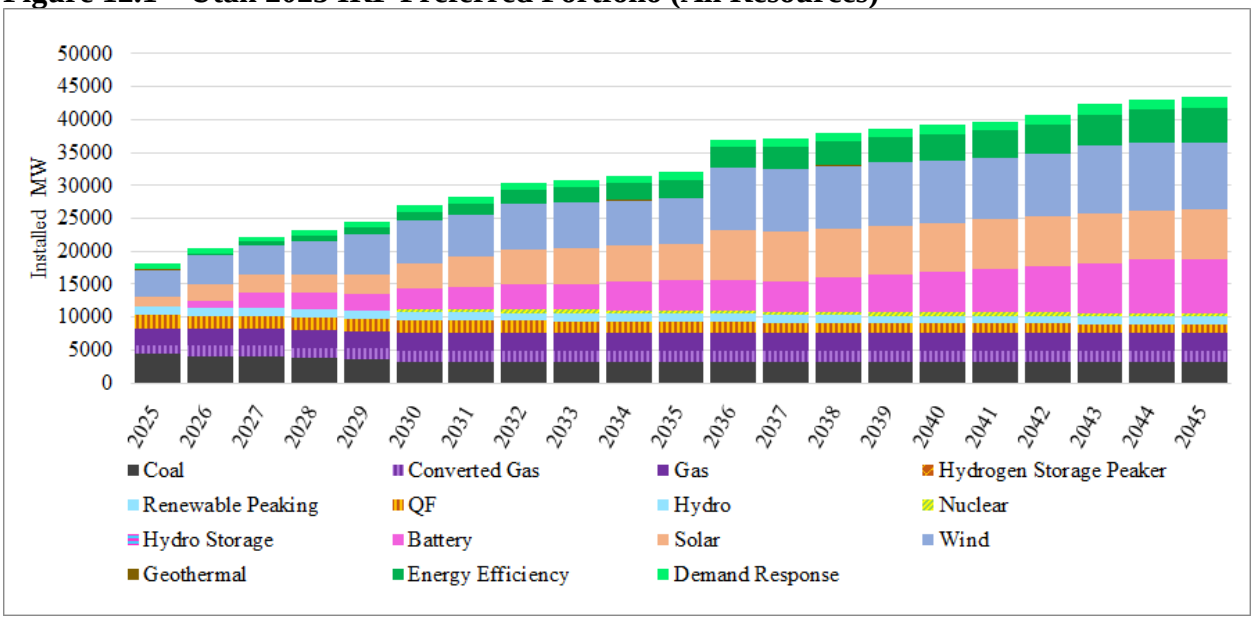
## The Utah 2025 IRP Preferred Portfolio

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 12.1 shows that PacifiCorp's Utah preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear.

The Utah 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2024 to 2026 timeframe.

The Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the Utah preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

**Figure 12.1 – Utah 2025 IRP Preferred Portfolio (All Resources)**




New since the 2023 IRP, the Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line, known as Energy Gateway South 2, running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This line is scheduled to be operational by 2036. Additionally, smaller upgrades will enhance transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 12.8 summarizes the incremental transmission projects in the Utah 2025 IRP Preferred Portfolio.

**Table 12.8 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]**

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| **2026** | Rebuild existing Cameron - Sigurd 138 kV | 250 | 250 | 250 | 30 | 100% | Utah South | Wasatch Front |
| **2027** | Cluster 1 Area 11 - Willamette Valley | 0 | 0 | 199 | 13 | 100% | n/a | n/a |
| | Serial queue - Central Oregon | 0 | 0 | 152 | 3 | 100% | n/a | n/a |
| **2028** | Cluster 2 Area 23 - Willamette Valley | 0 | 0 | 393 | 2 | 100% | n/a | n/a |
| **2030** | Cluster 1/2/3 - Walla Walla | 0 | 0 | 628 | 66 | 100% | n/a | n/a |
| **2031** | Cluster 1/2/3 - Walla Walla | 0 | 0 | 393 | 348 | 100% | n/a | n/a |
| | Walla Walla - Wine Country 230 kV | 400 | 400 | 400 | 145 | 100% | n/a | n/a |
| **2032** | Cluster 1 Area 14 - Summer Lake | 400 | 400 | 400 | 120 | 100% | Summer Lake | Hemingway |
| | Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV | 450 | 450 | 450 | 413 | 100% | Willamette Valley | Central OR |
| **2036** | Gateway South 2: Aeolus Clover #2 500 kV | 1,500 | 1,500 | 1,990 | 1,810 | 100% | Wyoming East | Clover |
| | Huntington – Clover 345 kV | 800 | 800 | 800 | 264 | 100% | Utah South | Wasatch Front |
| | Spanish Fork - Mercer 345 kV | 300 | 300 | 300 | 153 | 100% | Utah South | Wasatch Front |
| | West Cedar - Three Peaks 138 kV | 200 | 200 | 200 | 14 | 100% | Utah South | Wasatch Front |
| | S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV | 1,500 | 1,500 | 665 | 1,117 | 100% | Willamette Valley | Southern OR |
| **2041** | Serial through Cluster 1 Area 13 - Southern Oregon | 0 | 0 | 231 | 52 | 100% | n/a | n/a |
| **Grand Total** | | **5,800** | **5,800** | **7,451** | **4,551** | | | |

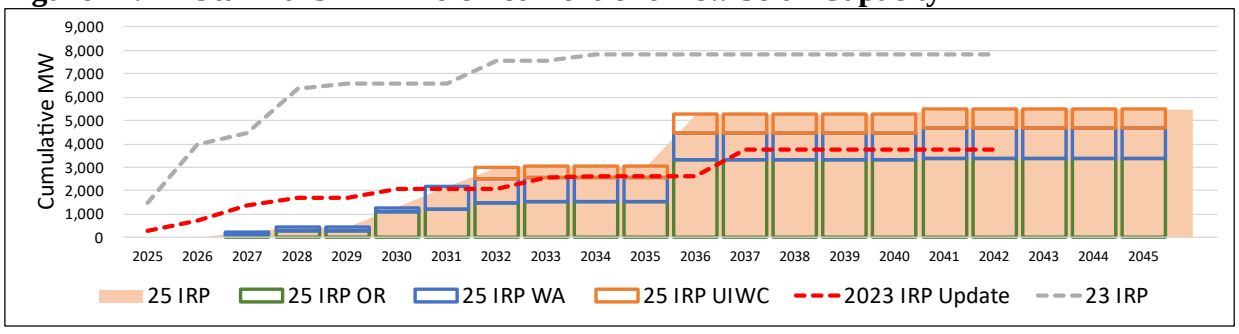
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

## New Solar Resources

The Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and more than 5,492 MW by the end of 2045, as shown in Figure 12.2.

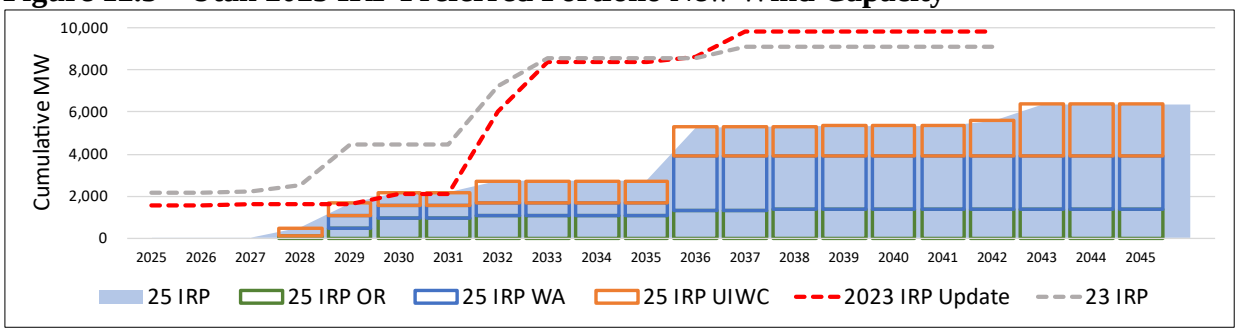
**Figure 12.2 – Utah 2025 IRP Preferred Portfolio New Solar Capacity**




## New Wind Resources

As shown in Figure 12.3, PacifiCorp's Utah 2025 IRP preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379 MW of cumulative new wind by the end of 2045.

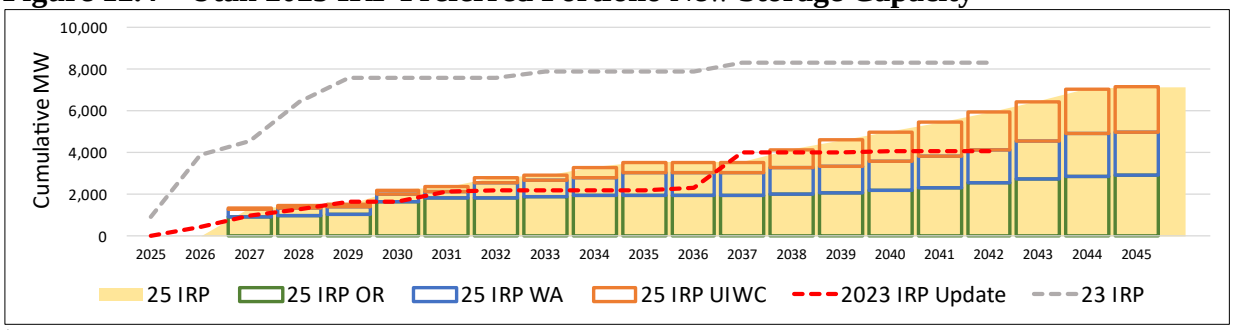
**Figure 12.3 – Utah 2025 IRP Preferred Portfolio New Wind Capacity**




## New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 12.4. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4 and 8-hour lithium-ion storage. By year-end 2030, the 2025 draft IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

**Figure 12.4 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1]**

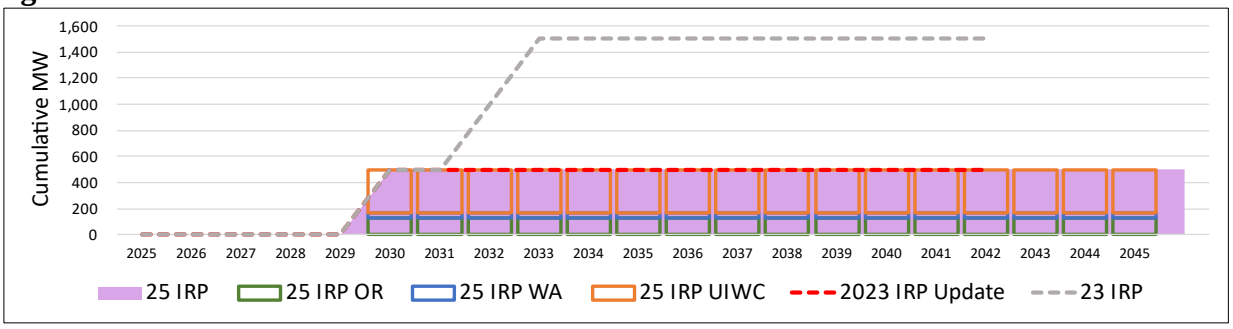



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

## New Nuclear Resources

The Utah 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 12.5, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by summer 2030.

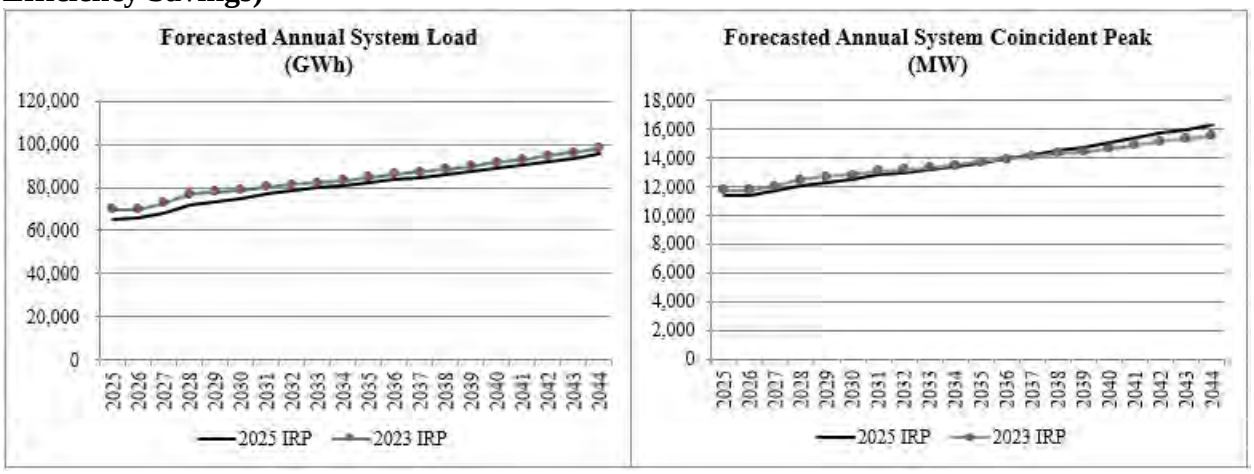
**Figure 12.5 – 2025 IRP New Nuclear**




## Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 12.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, lowering the commercial forecast.

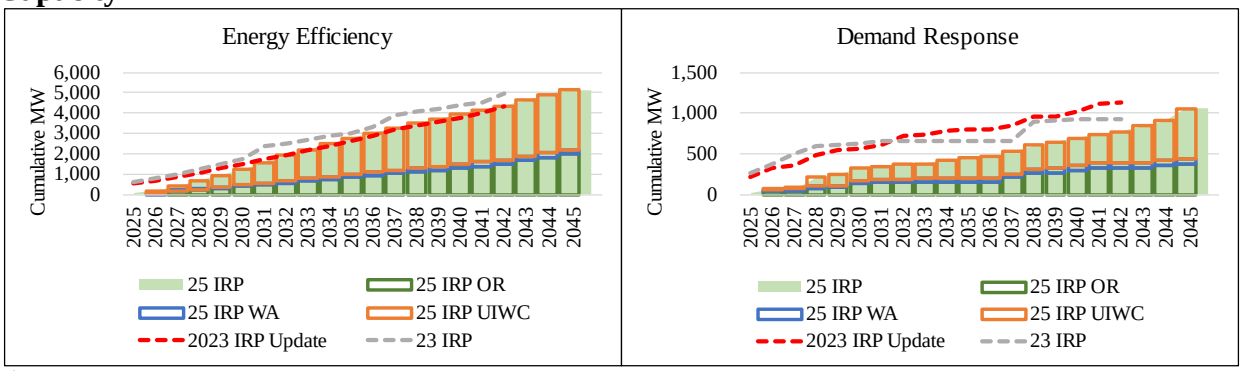
**Figure 12.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)**




DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 12.7 compares total energy efficiency capacity savings in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and includes 5,149 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 12.7 compares cumulative demand response program capacity in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP Update preferred portfolio and does not include capacity from existing programs. The 2025 draft IRP has a cumulative capacity of demand response programs reaching 695 MW by 2040. By year-end 2045, the Utah 2025 IRP preferred portfolio has a cumulative capacity of demand response programs reaching 1,052 MW, a 6.3% decrease from the cumulative capacity of demand response programs by the end of the planning horizon in the 2023 IRP Update (1,123 MW).

**Figure 12.7 – Utah 2025 IRP preferred portfolio Energy Efficiency and Demand Response Capacity**

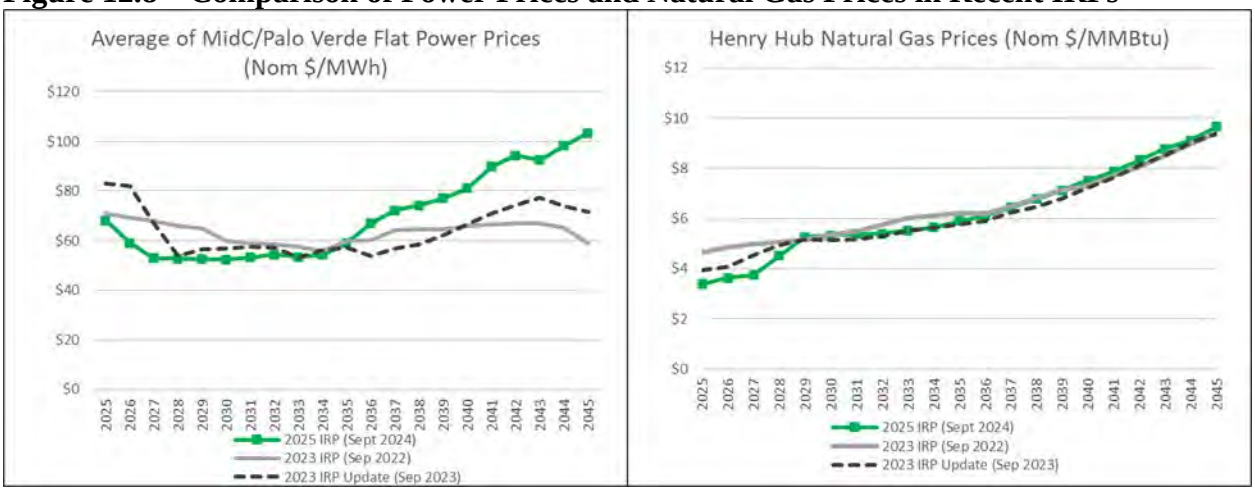



[1] Energy efficiency and demand response in the 2023 IRP Update began escalating two years prior to when escalation begins in the 2025 draft IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 draft IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP Update, the end of the planning horizon.

## Wholesale Power Market Prices and Purchases

Figure 12.8 illustrates that the Utah 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 12.8 reports that the Utah 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

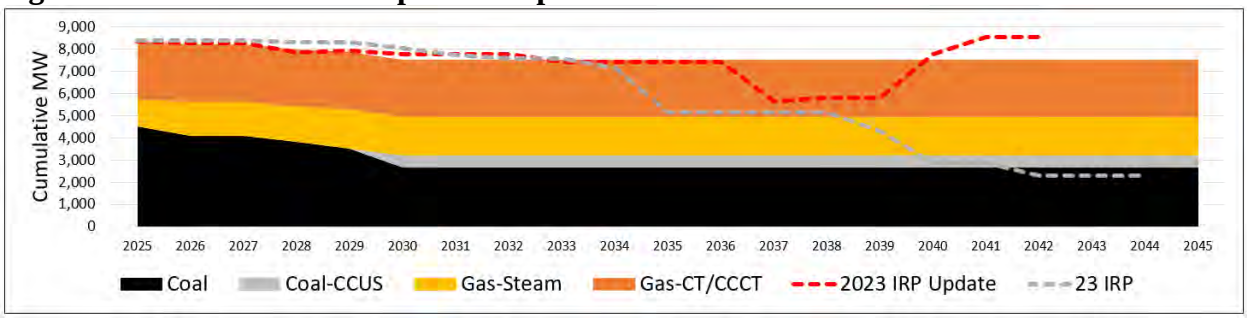
**Figure 12.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs**




## Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be reasonably available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 12.9, the Utah 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386.2 MW of minority-owned coal, and an additional 220 MW of majority-owned coal by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

**Figure 12.9 – Utah 2025 IRP preferred portfolio Thermal Resources**




A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 12.9. In addition to these

coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[3]

**Table 12.9 – 2025 IRP Coal Resource Results**

| Majority-Owned Coal | | | |
|---|---|---|---|
| Unit | Utah 2025 IRP Retirement Year | | 2023 IRP Retirement Year |
| | Selected w/o 111(d) Regulation | Selected w/ 111(d) Regulation | As Selected |
| Dave Johnston 1 & 2 | Not retired (Gas conversion 2029) | No change | 2028 |
| Dave Johnston 3 | 2027 (Clean air compliance) | No change | 2027 (Clean air compliance) |
| Dave Johnston 4 | Not retired | Not retired (Gas conversion 2030) | 2039 |
| Hunter 1 | Not retired | Not retired (Alt. fuel conv. 2030) | 2031 |
| Hunter 2 & 3 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Huntington 1 & 2 | Not retired | Not retired (Alt. fuel conv. 2030) | 2032 |
| Jim Bridger 1 & 2 | Not retired (Gas conversion 2024) | No change | 7 (Gas conversion 2024) |
| Jim Bridger 3 & 4 | Not retired (CCS conversion 2030) | No change | 2037 (Gas conversion 2030) |
| Naughton 1 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Naughton 2 | Not retired (Gas conversion 2026) | No change | 2036 (Gas conversion 2026) |
| Wyodak | Not retired | 2032 | 2039 |

| Minority-Owned Coal | | |
|---|---|---|
| Unit | 2025 IRP Retirement Year | 2023 IRP Retirement Year |
| | As Input | As Input |
| Colstrip 3 | 2025 (Transfer capacity to unit 4) | 2025 (Transfer capacity to unit 4) |
| Colstrip 4 | 2029 (PacifiCorp exit) | 2029 (PacifiCorp exit) |
| Craig 1 | 2025 (Assumed end of life) | 2025 (Assumed end of life) |
| Craig 2 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 1 | 2028 (Assumed end of life) | 2028 (Assumed end of life) |
| Hayden 2 | 2027 (Assumed end of life) | 2027 (Assumed end of life) |

## Carbon Dioxide Equivalent Emissions

The Utah 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total ($CO_2e$) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, storage and transmission advancements; and Regional Haze compliance that capitalizes on flexibility.

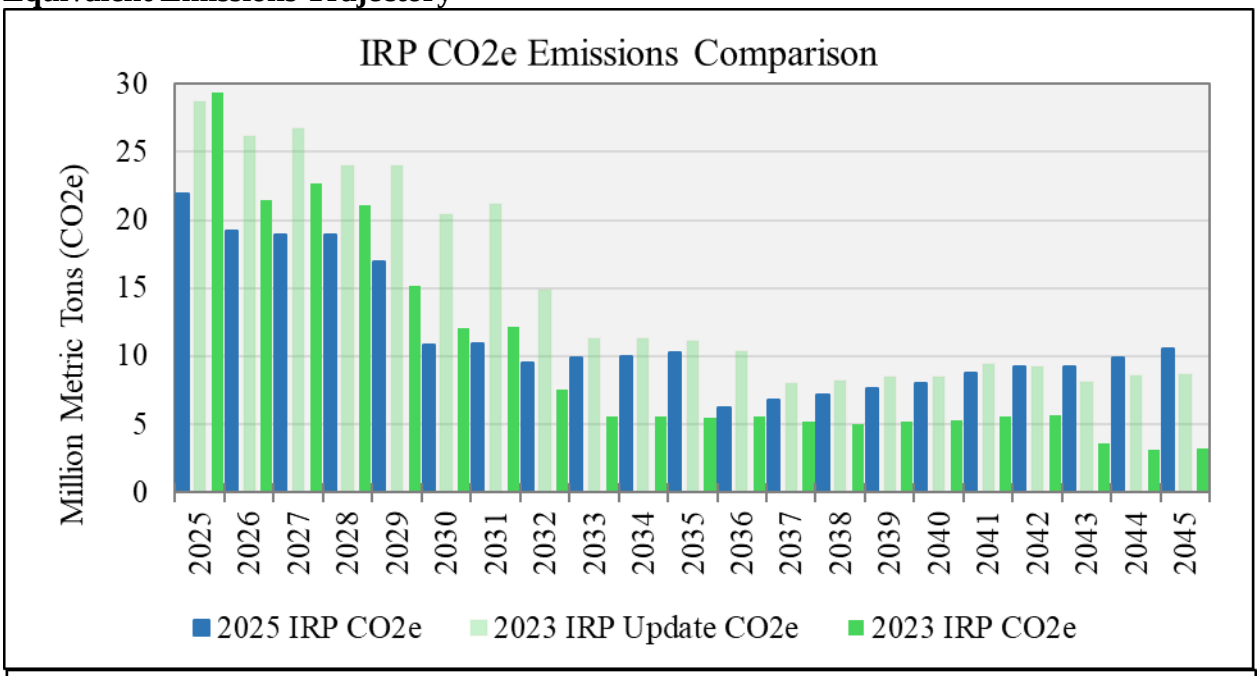
The chart on the left in Figure 12.10 compares projected annual $CO_2e$ emissions across the Utah 2025 IRP, 2023 IRP, and 2023 IRP Update preferred portfolios and is inclusive of emissions attributed to market purchases. The Utah 2025 IRP delivers greater emission reductions between 2025 to 2032 outperforming both the 2023 IRP and 2023 IRP Update, with average annual CO2e emissions down 8% by 2030 relative to the 2023 IRP. After 2032, emissions are forecasted to rise moderately above the 2023 IRP due in part to a higher load forecast in the Utah 2025 IRP and the expiration of existing contracted resources. The difference in emissions from the 2023 IRP also reflects the Utah 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing

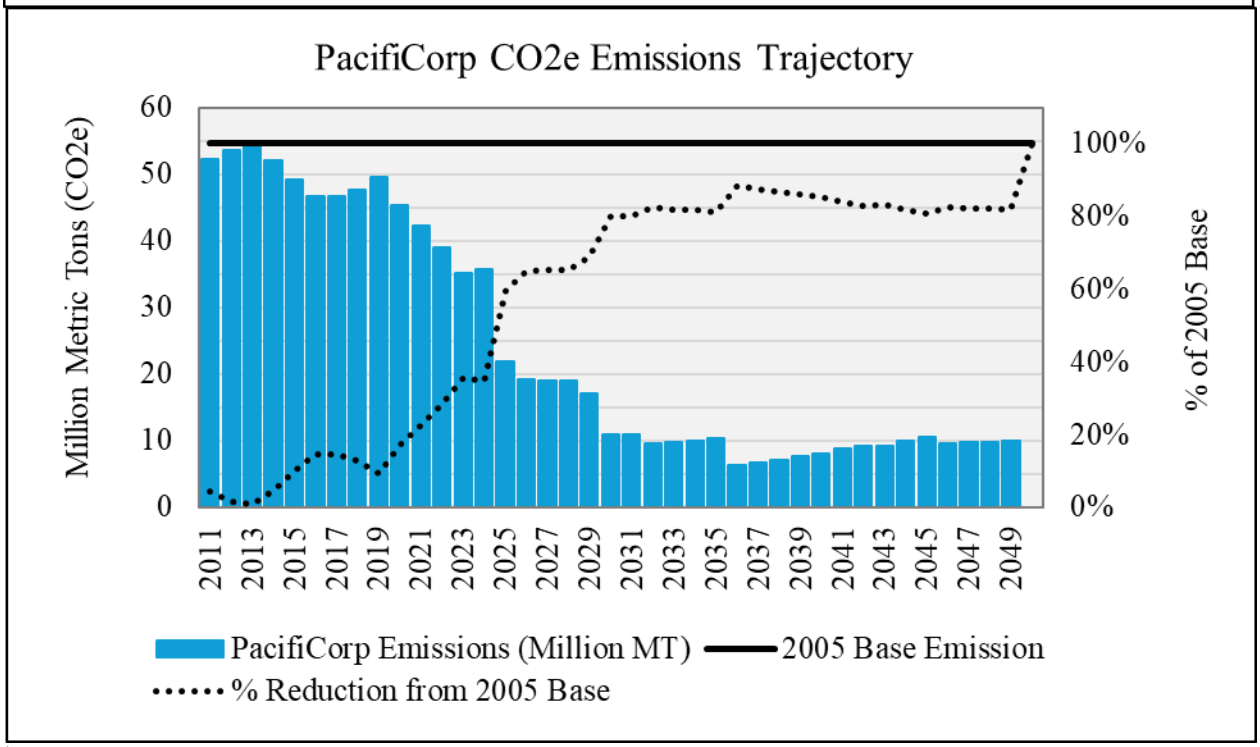
[3] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

existing coal plants to operate through the planning period at a reduced capacity. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals. By the end of the planning horizon, system CO2e emissions are projected to fall from 22.0 million metric tons in 2025 to 10.6 million tons in 2045—a reduction of 52 percent.

The chart on the right in Figure 12.10 includes historical data, assigns emissions at a rate of 0.428 metric tons $CO_2$ equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that, relative to a 2005 baseline of 54.6 million metric tons, system CO2 equivalent emissions are down 60 percent in 2025, 80 percent in 2030, and 85 percent in 2040.

**Figure 12.10 – Utah 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]**




[1] PacifiCorp $CO_2$ equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. 2023 emissions have yet to be updated for actuals and 2024 emissions were not forecasted in the 2025 IRP. Therefore both 2023 and 2024 reflect the forecast from the 2023 IRP. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the Utah 2025 IRP preferred portfolio with emissions from specified sources reported in $CO_2$ equivalent. Market purchases are assigned a default emission factor (0.428 metric tons $CO_2e$/MWh) – emissions from sales are not removed. Beyond 2045, emissions reflect the rolling average emissions of each resource from the Utah 2025 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

## Renewable Portfolio Standards

PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the Utah 2025 IRP preferred portfolio.

## Capacity and Energy

Figure 12.13 and Figure 12.14 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[4] On an energy basis, coal generation drops below 20 percent in 2026, falling below 10 percent in 2036, and remaining below 10 percent through the end of the planning period. On a capacity basis, coal resources drop to 12 percent. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources and DSM resources.

[4]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

**Figure 12.11 – Projected Energy Mix with Preferred Portfolio Resources**

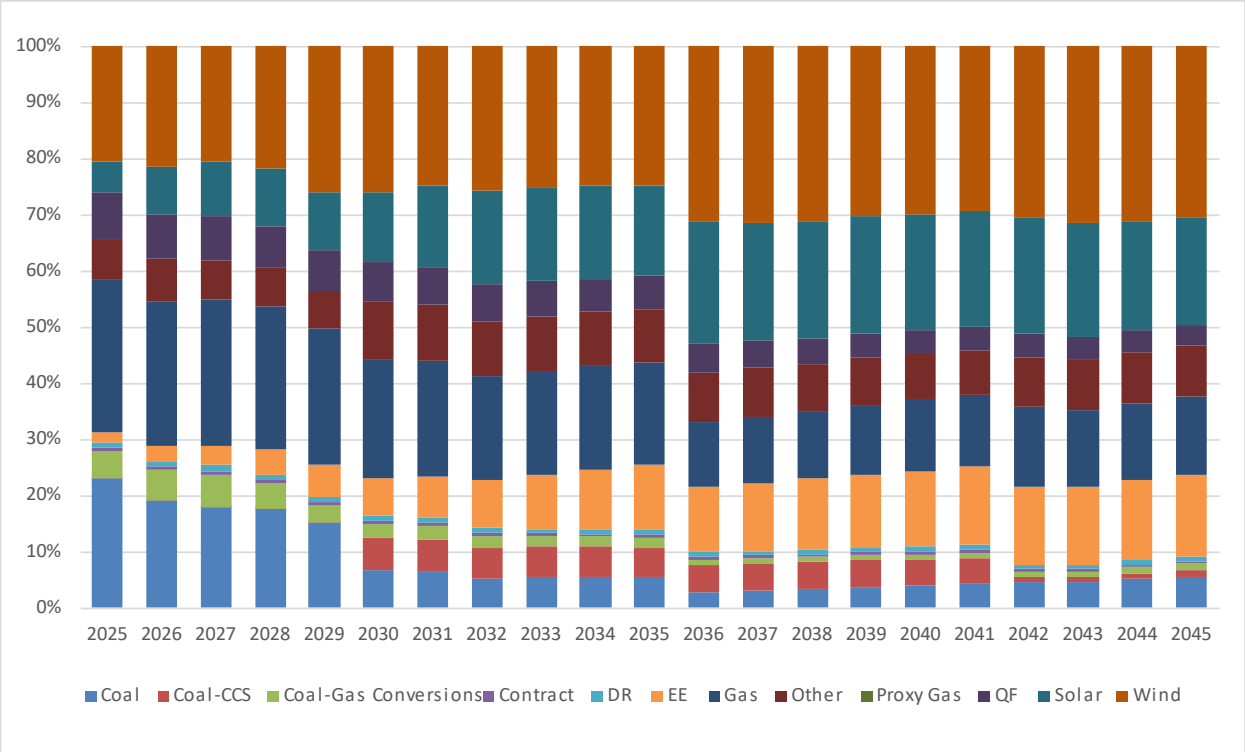
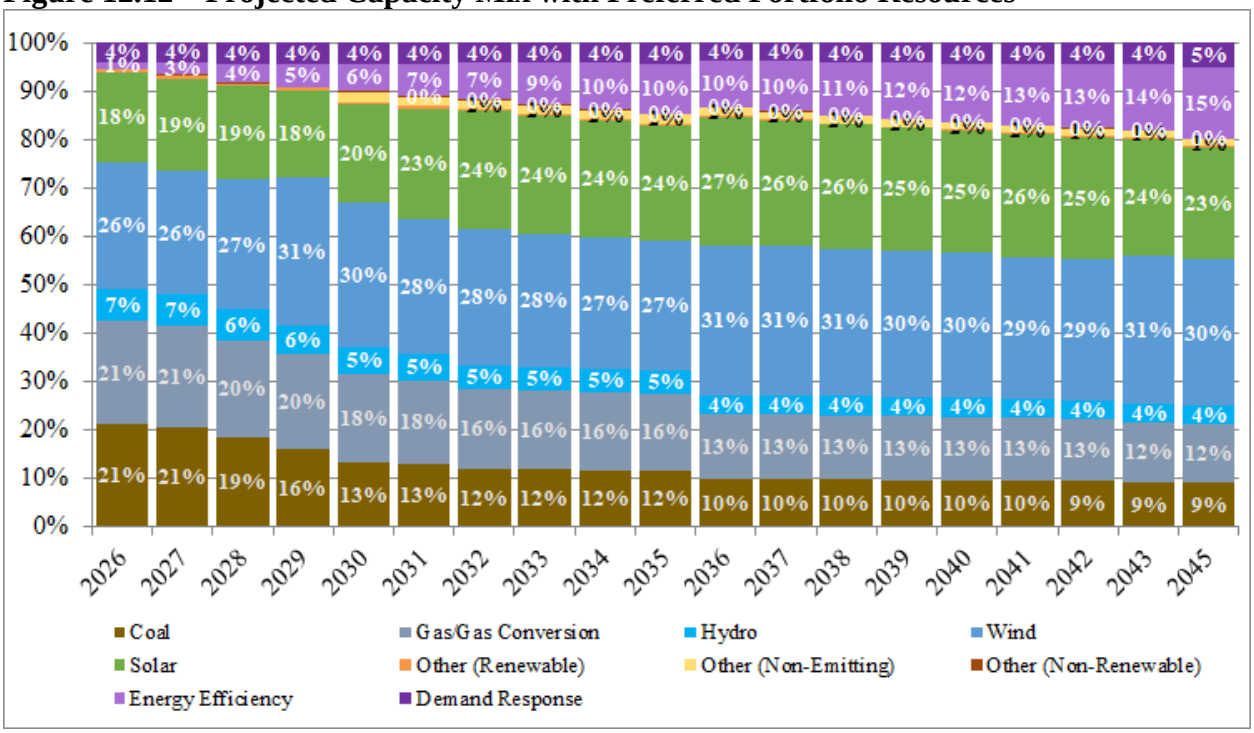



**Figure 12.12 – Projected Capacity Mix with Preferred Portfolio Resources**



## Detailed Preferred Portfolio

Table 12.10 provides line-item detail of PacifiCorp's Utah 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon.

Table 12.11 and Table 12.12 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon.

Table 12.13 and Table 12.14 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

# Table 12.10 – PacifiCorp's Utah 2025 IRP Preferred Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| **Resource** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 89 | 89 | 238 | 262 | 270 | 285 | 342 | 329 | 308 | 282 | 265 | 255 | 250 | 233 | 220 | 208 | 201 | 232 | 283 | 269 | 239 | 5,149 |
| DSM - Demand Response | 18 | 40 | 11 | 144 | 33 | 81 | 13 | 36 | 2 | 46 | 24 | 12 | 66 | 76 | 42 | 51 | 46 | 33 | 71 | 63 | 144 | 1,052 |
| Renewable - Wind | - | - | - | 486 | 804 | - | - | 451 | - | - | 3 | 2,327 | - | - | - | - | - | - | - | - | - | 4,071 |
| Renewable - Small Scale Wind | - | - | - | - | 380 | 505 | 4 | 85 | - | - | - | 246 | 4 | 37 | 9 | - | - | 236 | 802 | - | - | 2,308 |
| Renewable - Utility Solar | - | - | 245 | 182 | - | 848 | 896 | 805 | 49 | 5 | - | 2,221 | 4 | - | - | - | 237 | - | - | - | - | 5,492 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery | - | 520 | 1,297 | 116 | - | 39 | - | 416 | 3 | 317 | 176 | - | 11 | 253 | 10 | 81 | 105 | 488 | 257 | 279 | 15 | 4,383 |
| Renewable - Battery (Long Duration) | - | - | 1 | 26 | 62 | 655 | 166 | 22 | 93 | 88 | 67 | - | - | 326 | 466 | 312 | 325 | - | 264 | 332 | 80 | 3,285 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Owned | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| Gas Plant Retirements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Hydro | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Non-Thermal | - | - | - | - | - | - | - | - | - | (3) | - | - | - | (32) | - | - | - | - | - | - | - | (35) |
| Retire - Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Retire - Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Expire - Wind PPA | - | (64) | - | - | - | (99) | (200) | - | - | - | - | - | - | - | - | - | (333) | - | - | - | - | (696) |
| Expire - Solar PPA | - | - | - | (2) | - | - | (9) | - | - | - | - | - | (100) | - | - | - | (65) | - | - | (230) | - | (407) |
| Expire - QF | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (47) | (3) | (2) | (52) |
| Expire - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | (20) |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **107** | **502** | **1,792** | **961** | **1,426** | **1,966** | **1,212** | **2,144** | **455** | **735** | **535** | **5,061** | **235** | **893** | **747** | **652** | **516** | **989** | **1,630** | **710** | **456** | |

# Table 12.11 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,959 | 3,567 | 3,567 | 3,375 | 3,090 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 |
| Gas | 2,984 | 3,294 | 3,294 | 3,295 | 3,469 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 246 | 224 | 218 | 211 | 205 | 189 | 168 | 162 | 157 | 151 |
| Solar | 342 | 499 | 488 | 476 | 464 | 453 | 441 | 429 | 418 | 406 |
| Other Renewable | 46 | 45 | 44 | 42 | 41 | 40 | 38 | 37 | 36 | 34 |
| Storage | 1 | 939 | 925 | 909 | 894 | 879 | 865 | 849 | 834 | 819 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 413 | 404 | 395 | 386 | 377 | 368 | 359 | 348 | 334 | 323 |
| Demand Response | 305 | 300 | 295 | 290 | 286 | 281 | 276 | 271 | 266 | 262 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 0 | (639) | (822) | (627) | (335) | (1,131) | (1,021) | (595) | (628) | (494) |
| **East Existing Resources** | **8,373** | **8,709** | **8,480** | **8,434** | **8,567** | **7,549** | **7,598** | **7,975** | **7,889** | **7,974** |
| Additional Proxy/Short-Term Purchases | 190 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 |
| Wind | 0 | 0 | 0 | 85 | 185 | 268 | 263 | 273 | 267 | 263 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 136 | 160 | 220 | 867 | 1,029 | 1,049 | 1,139 | 1,224 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 |
| Demand Response | 0 | 0 | 0 | 73 | 92 | 106 | 106 | 127 | 127 | 157 |
| **East Planned Resources** | **190** | **0** | **137** | **319** | **499** | **1,543** | **1,701** | **1,751** | **1,836** | **1,947** |
| **East Total Resources** | **8,563** | **8,710** | **8,617** | **8,753** | **9,065** | **9,092** | **9,299** | **9,726** | **9,725** | **9,920** |
| Load | 7,734 | 7,947 | 7,952 | 8,230 | 8,667 | 8,855 | 9,050 | 9,335 | 9,335 | 9,284 |
| Distributed Generation | (157) | (143) | (186) | (234) | (285) | (341) | (400) | (458) | (515) | (354) |
| Energy Efficiency | (92) | (191) | (234) | (346) | (457) | (566) | (561) | (852) | (880) | (996) |
| **East Total obligation** | **7,485** | **7,613** | **7,532** | **7,651** | **7,924** | **7,948** | **8,089** | **8,025** | **7,940** | **7,934** |
| **East Reserve Margin** | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 15.0% | 21.2% | 22.5% | 25.0% |
| **West** | | | | | | | | | | |
| Coal | 140 | 133 | 133 | 133 | 133 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 69 | 67 | 65 | 62 | 60 | 58 | 52 | 50 | 48 | 46 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 229 | 224 | 212 | 207 | 198 | 194 | 188 | 178 | 174 | 170 |
| Demand Response | 60 | 59 | 58 | 58 | 57 | 56 | 55 | 55 | 54 | 53 |
| Transfers | 0 | 639 | 822 | 627 | 335 | 1,131 | 1,021 | 595 | 628 | 494 |
| **West Existing Resources** | **1,927** | **2,551** | **2,719** | **2,516** | **2,212** | **2,868** | **2,745** | **2,307** | **2,332** | **2,191** |
| Additional Proxy/Short-Term Purchases | 2,145 | 1,711 | 568 | 720 | 1,079 | 166 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 64 | 64 | 64 | 112 | 112 | 111 |
| Solar | 0 | 0 | 133 | 225 | 218 | 627 | 1,031 | 1,363 | 1,333 | 1,285 |
| Storage | 0 | 0 | 847 | 920 | 908 | 923 | 912 | 1,186 | 1,171 | 1,369 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 6 | 9 | 42 | 44 | 44 | 48 | 49 | 49 | 50 |
| **West Planned Resources** | **2,145** | **1,718** | **1,559** | **1,907** | **2,313** | **1,825** | **2,055** | **2,710** | **2,665** | **2,815** |
| **West Total Resources** | **4,072** | **4,269** | **4,278** | **4,423** | **4,525** | **4,693** | **4,799** | **5,017** | **4,998** | **5,006** |
| Load | 3,672 | 3,826 | 3,938 | 4,121 | 4,271 | 4,482 | 4,609 | 4,828 | 4,946 | 4,887 |
| Distributed Generation | (49) | (54) | (75) | (99) | (124) | (152) | (182) | (213) | (244) | (148) |
| Energy Efficiency | (63) | (41) | (123) | (157) | (191) | (227) | (231) | (229) | (334) | (364) |
| **West Total obligation** | **3,560** | **3,731** | **3,740** | **3,866** | **3,955** | **4,102** | **4,195** | **4,386** | **4,368** | **4,376** |
| **West Reserve Margin** | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% |
| **System** | | | | | | | | | | |
| **Total Resources** | 12,635 | 12,978 | 12,895 | 13,175 | 13,590 | 13,785 | 14,099 | 14,743 | 14,723 | 14,926 |
| **Obligation** | 11,045 | 11,345 | 11,272 | 11,517 | 11,879 | 12,050 | 12,284 | 12,410 | 12,308 | 12,310 |
| **Planning Reserves (14.4%)** | 1,590 | 1,634 | 1,623 | 1,658 | 1,711 | 1,735 | 1,769 | 1,787 | 1,772 | 1,773 |
| **Obligation + Reserves** | 12,635 | 12,978 | 12,895 | 13,175 | 13,590 | 13,785 | 14,053 | 14,197 | 14,081 | 14,082 |
| **System Position** | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 546 | 642 | 844 |
| **Reserve Margin** | **14.4%** | **14.4%** | **14.4%** | **14.4%** | **14.4%** | **14.4%** | **14.8%** | **18.8%** | **19.6%** | **21.3%** |

# Table 12.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 | 2,926 |
| Gas | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 | 3,470 |
| Hydroelectric | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Wind | 145 | 140 | 134 | 128 | 122 | 117 | 81 | 77 | 73 | 69 | 65 |
| Solar | 395 | 383 | 343 | 332 | 322 | 311 | 300 | 290 | 279 | 246 | 236 |
| Other Renewable | 33 | 32 | 30 | 11 | 11 | 10 | 9 | 9 | 8 | 8 | 0 |
| Storage | 804 | 788 | 773 | 759 | 744 | 728 | 714 | 699 | 684 | 668 | 654 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 314 | 302 | 240 | 231 | 223 | 211 | 204 | 196 | 189 | 182 | 176 |
| Demand Response | 257 | 252 | 247 | 243 | 238 | 233 | 228 | 223 | 218 | 214 | 209 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (469) | (310) | (491) | (366) | (567) | (653) | (663) | (627) | (708) | (607) | (765) |
| **East Existing Resources** | **7,950** | **8,060** | **7,749** | **7,811** | **7,564** | **7,430** | **7,346** | **7,339** | **7,216** | **7,252** | **7,047** |
| Additional Proxy/Short-Term Purcha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Wind | 258 | 641 | 628 | 621 | 609 | 596 | 583 | 601 | 691 | 675 | 658 |
| Solar | 0 | 316 | 306 | 297 | 287 | 278 | 268 | 258 | 249 | 239 | 230 |
| Storage | 1,288 | 1,286 | 1,284 | 1,605 | 2,064 | 2,371 | 2,690 | 2,688 | 2,947 | 3,273 | 3,350 |
| Nuclear | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 302 |
| Demand Response | 172 | 181 | 189 | 198 | 230 | 241 | 251 | 265 | 294 | 307 | 401 |
| **East Planned Resources** | **2,022** | **2,726** | **2,711** | **3,024** | **3,494** | **3,789** | **4,095** | **4,116** | **4,484** | **4,799** | **4,943** |
| **East Total Resources** | **9,972** | **10,786** | **10,460** | **10,835** | **11,058** | **11,219** | **11,441** | **11,454** | **11,700** | **12,051** | **11,990** |
| Load | 9,411 | 9,557 | 9,767 | 9,935 | 10,083 | 10,201 | 10,339 | 10,480 | 10,664 | 10,745 | 10,883 |
| Distributed Generation | (385) | (415) | (445) | (474) | (503) | (529) | (557) | (584) | (609) | (635) | (660) |
| Energy Efficiency | (1,110) | (1,151) | (1,024) | (1,333) | (1,462) | (1,515) | (1,580) | (1,315) | (1,562) | (1,583) | (1,613) |
| **East Total obligation** | **7,916** | **7,990** | **8,298** | **8,129** | **8,118** | **8,156** | **8,202** | **8,581** | **8,492** | **8,528** | **8,610** |
| **East Reserve Margin** | 26.0% | 35.0% | 26.1% | 33.3% | 36.2% | 37.6% | 39.5% | 33.5% | 37.8% | 41.3% | 39.3% |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydroelectric | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 | 712 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 45 | 43 | 41 | 39 | 37 | 35 | 13 | 12 | 11 | 11 | 10 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 165 | 160 | 143 | 138 | 133 | 129 | 125 | 121 | 100 | 96 | 94 |
| Demand Response | 52 | 52 | 51 | 50 | 49 | 49 | 48 | 47 | 46 | 46 | 45 |
| Transfers | 469 | 310 | 491 | 366 | 567 | 653 | 663 | 627 | 708 | 607 | 765 |
| **West Existing Resources** | **2,159** | **1,992** | **2,153** | **2,021** | **2,213** | **2,293** | **2,276** | **2,235** | **2,293** | **2,187** | **2,341** |
| Additional Proxy/Short-Term Purcha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 111 | 111 | 110 | 110 | 109 | 109 | 109 | 108 | 108 | 107 | 107 |
| Solar | 1,235 | 1,444 | 1,382 | 1,320 | 1,259 | 1,197 | 1,208 | 1,140 | 1,074 | 1,008 | 942 |
| Storage | 1,466 | 1,444 | 1,431 | 1,569 | 1,551 | 1,576 | 1,617 | 1,881 | 2,001 | 2,130 | 2,102 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 50 | 50 | 85 | 107 | 108 | 128 | 138 | 141 | 142 | 170 | 175 |
| **West Planned Resources** | **2,861** | **3,048** | **3,008** | **3,106** | **3,027** | **3,010** | **3,071** | **3,270** | **3,325** | **3,415** | **3,327** |
| **West Total Resources** | **5,020** | **5,040** | **5,161** | **5,127** | **5,240** | **5,303** | **5,347** | **5,505** | **5,618** | **5,603** | **5,668** |
| Load | 4,944 | 5,009 | 5,082 | 5,189 | 5,258 | 5,330 | 5,397 | 5,473 | 5,660 | 5,651 | 5,730 |
| Distributed Generation | (163) | (177) | (192) | (206) | (221) | (234) | (249) | (263) | (277) | (290) | (304) |
| Energy Efficiency | (394) | (426) | (378) | (502) | (457) | (461) | (475) | (399) | (473) | (463) | (471) |
| **West Total obligation** | **4,388** | **4,406** | **4,512** | **4,481** | **4,581** | **4,635** | **4,674** | **4,812** | **4,910** | **4,897** | **4,955** |
| **West Reserve Margin** | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% | 14.4% |
| **System** | | | | | | | | | | | |
| **Total Resources** | 14,992 | 15,826 | 15,621 | 15,961 | 16,299 | 16,522 | 16,788 | 16,959 | 17,318 | 17,653 | 17,658 |
| **Obligation** | 12,304 | 12,396 | 12,810 | 12,610 | 12,699 | 12,791 | 12,876 | 13,393 | 13,403 | 13,425 | 13,564 |
| **Planning Reserves (14.4%)** | 1,772 | 1,785 | 1,845 | 1,816 | 1,829 | 1,842 | 1,854 | 1,929 | 1,930 | 1,933 | 1,953 |
| **Obligation + Reserves** | 14,076 | 14,181 | 14,654 | 14,426 | 14,528 | 14,633 | 14,730 | 15,321 | 15,333 | 15,358 | 15,518 |
| **System Position** | 917 | 1,645 | 967 | 1,536 | 1,771 | 1,888 | 2,059 | 1,638 | 1,985 | 2,295 | 2,141 |
| **Reserve Margin** | **21.8%** | **27.7%** | **21.9%** | **26.6%** | **28.3%** | **29.2%** | **30.4%** | **26.6%** | **29.2%** | **31.5%** | **30.2%** |

# Table 12.13 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

| East | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 4,147 | 3,733 | 3,733 | 3,498 | 3,184 | 3,014 | 3,014 | 3,015 | 3,015 | 3,015 |
| Gas | 3,003 | 3,334 | 3,334 | 3,335 | 3,526 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 2,037 | 1,929 | 1,836 | 1,748 | 1,616 | 1,456 | 1,377 | 1,300 | 1,226 | 1,154 |
| Solar | 77 | 104 | 101 | 98 | 95 | 92 | 89 | 86 | 83 | 80 |
| Other Renewable | 41 | 39 | 38 | 37 | 35 | 34 | 33 | 31 | 30 | 28 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 186 | 181 | 177 | 171 | 167 | 162 | 155 | 150 | 130 | 125 |
| Demand Response | 139 | 135 | 132 | 129 | 125 | 122 | 119 | 116 | 112 | 109 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (1,600) | (1,600) | (1,281) | (1,299) | (1,403) | (1,600) | (1,600) | (1,176) | (1,225) | (1,002) |
| **East Existing Resources** | **8,062** | **7,890** | **8,104** | **7,749** | **7,379** | **6,841** | **6,748** | **7,083** | **6,931** | **7,070** |
| Additional Proxy/Short-Term Purchases | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 |
| Wind | 0 | 0 | 0 | 225 | 484 | 691 | 672 | 688 | 666 | 645 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 90 | 113 | 173 | 821 | 983 | 1,003 | 1,093 | 1,178 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 |
| Demand Response | 0 | 0 | 0 | 73 | 92 | 106 | 106 | 127 | 127 | 157 |
| **East Planned Resources** | **0** | **0** | **90** | **412** | **750** | **1,920** | **2,063** | **2,120** | **2,188** | **2,283** |
| **East Total Resources** | **8,062** | **7,890** | **8,194** | **8,161** | **8,129** | **8,760** | **8,811** | **9,202** | **9,119** | **9,353** |
| Load | 5,724 | 6,099 | 6,174 | 6,448 | 6,759 | 6,698 | 6,869 | 7,153 | 7,223 | 7,397 |
| Distributed Generation | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| Energy Efficiency | (63) | (116) | (174) | (243) | (311) | (385) | (403) | (528) | (613) | (695) |
| **East Total obligation** | **5,659** | **5,981** | **5,997** | **6,201** | **6,443** | **6,306** | **6,459** | **6,617** | **6,601** | **6,693** |
| **East Reserve Margin** | 42.5% | 31.9% | 36.6% | 31.6% | 26.2% | 38.9% | 36.4% | 39.1% | 38.1% | 39.7% |
| **West** | | | | | | | | | | |
| Coal | 147 | 147 | 147 | 147 | 147 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 64 | 61 | 59 | 57 | 54 | 52 | 50 | 47 | 45 | 43 |
| Solar | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 68 | 68 | 60 | 60 | 57 | 56 | 56 | 55 | 55 | 55 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 1,600 | 1,600 | 1,281 | 1,299 | 1,403 | 1,600 | 1,600 | 1,176 | 1,225 | 1,002 |
| **West Existing Resources** | **3,341** | **3,339** | **3,010** | **3,026** | **3,124** | **3,171** | **3,167** | **2,740** | **2,787** | **2,561** |
| Additional Proxy/Short-Term Purchases | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 64 | 64 | 64 | 112 | 111 | 111 |
| Solar | 0 | 0 | 34 | 57 | 55 | 158 | 259 | 340 | 331 | 316 |
| Storage | 0 | 0 | 1,102 | 1,197 | 1,180 | 1,200 | 1,182 | 1,538 | 1,517 | 1,770 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 6 | 9 | 42 | 44 | 44 | 48 | 49 | 49 | 50 |
| **West Planned Resources** | **0** | **6** | **1,146** | **1,297** | **1,343** | **1,466** | **1,553** | **2,039** | **2,008** | **2,248** |
| **West Total Resources** | **3,341** | **3,345** | **4,156** | **4,322** | **4,467** | **4,637** | **4,720** | **4,778** | **4,794** | **4,809** |
| Load | 3,711 | 3,577 | 3,676 | 3,859 | 4,025 | 4,478 | 4,541 | 4,421 | 4,477 | 4,526 |
| Distributed Generation | (0) | (0) | (1) | (1) | (1) | (1) | (1) | (2) | (2) | (2) |
| Energy Efficiency | (45) | (79) | (118) | (157) | (199) | (246) | (236) | (328) | (370) | (407) |
| **West Total obligation** | **3,665** | **3,498** | **3,558** | **3,701** | **3,825** | **4,230** | **4,303** | **4,091** | **4,105** | **4,117** |
| **West Reserve Margin** | -8.8% | -4.4% | 16.8% | 16.8% | 16.8% | 9.6% | 9.7% | 16.8% | 16.8% | 16.8% |
| **System** | | | | | | | | | | |
| **Total Resources** | 11,404 | 11,235 | 12,350 | 12,484 | 12,596 | 13,397 | 13,531 | 13,980 | 13,913 | 14,161 |
| **Obligation** | 9,324 | 9,479 | 9,555 | 9,902 | 10,268 | 10,537 | 10,762 | 10,708 | 10,706 | 10,810 |
| **Planning Reserves (16.8%)** | 1,566 | 1,593 | 1,605 | 1,663 | 1,725 | 1,770 | 1,808 | 1,799 | 1,799 | 1,816 |
| **Obligation + Reserves** | 10,891 | 11,072 | 11,160 | 11,565 | 11,993 | 12,307 | 12,570 | 12,507 | 12,505 | 12,626 |
| **System Position** | 513 | 163 | 1,190 | 919 | 604 | 1,091 | 960 | 1,474 | 1,408 | 1,536 |
| **Reserve Margin** | **22.3%** | **18.5%** | **29.3%** | **26.1%** | **22.7%** | **27.2%** | **25.7%** | **30.6%** | **30.0%** | **31.0%** |

# Table 12.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

| East | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 | 3,015 |
| Gas | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 | 3,527 |
| Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Wind | 1,082 | 1,014 | 948 | 883 | 820 | 674 | 621 | 570 | 522 | 474 | 429 |
| Solar | 77 | 74 | 71 | 68 | 66 | 63 | 60 | 57 | 46 | 44 | 41 |
| Other Renewable | 27 | 26 | 24 | 8 | 8 | 8 | 7 | 6 | 6 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 121 | 103 | 98 | 95 | 91 | 87 | 83 | 79 | 75 | 72 | 68 |
| Demand Response | 106 | 103 | 99 | 96 | 93 | 89 | 86 | 83 | 80 | 76 | 73 |
| Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | (911) | (1,183) | (1,390) | (789) | (927) | (938) | (950) | (1,006) | (965) | (865) | (921) |
| **East Existing Resources** | **7,078** | **6,712** | **6,426** | **6,936** | **6,725** | **6,558** | **6,481** | **6,365** | **6,339** | **6,375** | **6,265** |
| Additional Proxy/Short-Term Purcha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Wind | 625 | 1,530 | 1,476 | 1,436 | 1,383 | 1,329 | 1,273 | 1,286 | 1,447 | 1,378 | 1,311 |
| Solar | 0 | 81 | 78 | 75 | 71 | 68 | 65 | 62 | 59 | 55 | 52 |
| Storage | 1,242 | 1,239 | 1,234 | 1,552 | 2,008 | 2,312 | 2,628 | 2,623 | 2,880 | 3,203 | 3,277 |
| Nuclear | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 301 | 302 |
| Demand Response | 172 | 181 | 189 | 198 | 230 | 241 | 251 | 265 | 294 | 307 | 401 |
| **East Planned Resources** | **2,342** | **3,334** | **3,281** | **3,564** | **3,996** | **4,254** | **4,521** | **4,540** | **4,983** | **5,247** | **5,345** |
| **East Total Resources** | **9,420** | **10,046** | **9,707** | **10,500** | **10,721** | **10,812** | **11,001** | **10,905** | **11,322** | **11,622** | **11,610** |
| Load | 7,321 | 7,508 | 7,595 | 7,732 | 7,856 | 7,991 | 8,169 | 8,340 | 8,450 | 8,525 | 8,664 |
| Distributed Generation | (11) | (11) | (12) | (13) | (13) | (14) | (14) | (14) | (15) | (15) | (16) |
| Energy Efficiency | (580) | (891) | (834) | (824) | (879) | (926) | (1,042) | (979) | (1,305) | (1,268) | (1,195) |
| **East Total obligation** | **6,730** | **6,606** | **6,749** | **6,896** | **6,964** | **7,052** | **7,113** | **7,347** | **7,131** | **7,242** | **7,453** |
| **East Reserve Margin** | 40.0% | 52.1% | 43.8% | 52.3% | 54.0% | 53.3% | 54.7% | 48.4% | 58.8% | 60.5% | 55.8% |
| **West** | | | | | | | | | | | |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 | 735 |
| Hydroelectric | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 |
| Wind | 41 | 39 | 36 | 34 | 32 | 30 | 28 | 26 | 24 | 22 | 20 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Renewable | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Qualifying Facilities | 55 | 53 | 53 | 52 | 51 | 51 | 50 | 50 | 49 | 49 | 49 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfers | 911 | 1,183 | 1,390 | 789 | 927 | 938 | 950 | 1,006 | 965 | 865 | 921 |
| **West Existing Resources** | **2,467** | **2,736** | **2,940** | **2,336** | **2,471** | **2,480** | **2,489** | **2,542** | **2,499** | **2,397** | **2,451** |
| Additional Proxy/Short-Term Purcha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Storage Peaker | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 111 | 110 | 110 | 109 | 109 | 109 | 108 | 108 | 107 | 107 | 106 |
| Solar | 301 | 349 | 331 | 312 | 294 | 276 | 274 | 254 | 235 | 215 | 195 |
| Storage | 1,893 | 1,865 | 1,845 | 2,021 | 1,997 | 2,027 | 2,076 | 2,412 | 2,564 | 2,722 | 2,685 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 50 | 50 | 85 | 107 | 108 | 128 | 138 | 141 | 142 | 170 | 175 |
| **West Planned Resources** | **2,355** | **2,374** | **2,372** | **2,549** | **2,508** | **2,539** | **2,596** | **2,914** | **3,048** | **3,213** | **3,162** |
| **West Total Resources** | **4,822** | **5,109** | **5,312** | **4,886** | **4,979** | **5,018** | **5,085** | **5,456** | **5,547** | **5,610** | **5,613** |
| Load | 4,773 | 4,920 | 4,989 | 4,941 | 5,062 | 5,136 | 5,276 | 5,289 | 5,398 | 5,345 | 5,467 |
| Distributed Generation | (2) | (3) | (3) | (3) | (3) | (3) | (3) | (4) | (4) | (4) | (4) |
| Energy Efficiency | (642) | (543) | (439) | (755) | (796) | (837) | (919) | (614) | (645) | (538) | (658) |
| **West Total obligation** | **4,128** | **4,374** | **4,548** | **4,183** | **4,263** | **4,297** | **4,353** | **4,671** | **4,749** | **4,803** | **4,805** |
| **West Reserve Margin** | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% |
| **System** | | | | | | | | | | | |
| **Total Resources** | 14,241 | 15,155 | 15,018 | 15,386 | 15,700 | 15,830 | 16,086 | 16,361 | 16,869 | 17,232 | 17,223 |
| **Obligation** | 10,858 | 10,980 | 11,297 | 11,079 | 11,227 | 11,348 | 11,466 | 12,018 | 11,880 | 12,045 | 12,258 |
| **Planning Reserves (16.8%)** | 1,564 | 1,581 | 1,627 | 1,595 | 1,617 | 1,634 | 1,651 | 1,731 | 1,711 | 1,735 | 1,765 |
| **Obligation + Reserves** | 12,422 | 12,561 | 12,924 | 12,674 | 12,843 | 12,983 | 13,117 | 13,749 | 13,591 | 13,780 | 14,023 |
| **System Position** | 1,820 | 2,594 | 2,095 | 2,711 | 2,857 | 2,848 | 2,969 | 2,612 | 3,278 | 3,452 | 3,200 |
| **Reserve Margin** | **31.2%** | **38.0%** | **32.9%** | **38.9%** | **39.8%** | **39.5%** | **40.3%** | **36.1%** | **42.0%** | **43.1%** | **40.5%** |

## Integrated Portfolio Resource Comparisons by Technology and Year

Table 12.15 through Table 12.25 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 12.26 through Table 12.28 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology.

### Table 12.15 – New Gas[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | 489 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 40 | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | 40 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

### Table 12.16 - Nuclear[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.17 – Renewable Peaking[1]

| Study | Cumulative Energy, Gwh | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.18 – DSM – Energy Efficiency

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | 89 | 89 | 238 | 262 | 270 | 285 | 342 | 329 | 308 | 282 | 265 | 255 | 250 | 233 | 220 | 208 | 201 | 232 | 283 | 269 | 239 |
| MR Base | 89 | 89 | 238 | 259 | 266 | 285 | 338 | 329 | 308 | 282 | 265 | 249 | 250 | 239 | 227 | 214 | 210 | 235 | 286 | 271 | 239 |
| MN - No Coal Post 2032 | 89 | 89 | 238 | 259 | 266 | 281 | 336 | 329 | 303 | 282 | 265 | 248 | 250 | 234 | 220 | 208 | 201 | 232 | 283 | 269 | 240 |
| MN - No CCS | 89 | 89 | 238 | 262 | 270 | 285 | 343 | 329 | 308 | 282 | 270 | 255 | 250 | 234 | 220 | 208 | 202 | 232 | 287 | 272 | 239 |
| MN - No Nuclear | 89 | 89 | 238 | 262 | 275 | 289 | 345 | 331 | 308 | 283 | 265 | 252 | 250 | 233 | 227 | 214 | 207 | 235 | 286 | 275 | 239 |
| MN - Offshore Wind | 89 | 89 | 238 | 259 | 270 | 285 | 338 | 329 | 308 | 283 | 265 | 252 | 250 | 233 | 219 | 208 | 207 | 232 | 283 | 271 | 236 |
| LN Base | 89 | 89 | 237 | 257 | 265 | 280 | 334 | 328 | 307 | 281 | 264 | 254 | 249 | 232 | 218 | 206 | 199 | 225 | 276 | 266 | 227 |
| HH Base | 89 | 89 | 244 | 268 | 276 | 291 | 347 | 333 | 312 | 286 | 268 | 268 | 261 | 243 | 229 | 217 | 210 | 235 | 286 | 272 | 240 |
| SC Base | 89 | 89 | 244 | 265 | 272 | 286 | 347 | 333 | 310 | 283 | 265 | 258 | 252 | 240 | 227 | 209 | 210 | 234 | 286 | 271 | 235 |

## Table 12.19 – DSM – Demand Response

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | 18 | 40 | 11 | 144 | 33 | 81 | 13 | 36 | 2 | 46 | 24 | 12 | 66 | 76 | 42 | 51 | 46 | 33 | 71 | 63 | 144 |
| MR Base | 18 | 40 | 11 | 126 | 43 | 76 | 12 | 39 | 2 | 46 | 16 | 12 | 80 | 80 | 42 | 48 | 48 | 34 | 71 | 43 | 62 |
| MN - No Coal Post 2032 | 18 | 40 | 11 | 141 | 32 | 60 | 47 | 27 | 2 | 46 | 16 | 12 | 66 | 84 | 42 | 48 | 48 | 34 | 71 | 62 | 43 |
| MN - No CCS | 18 | 40 | 11 | 139 | 38 | 81 | 13 | 36 | 2 | 46 | 24 | 12 | 66 | 76 | 45 | 48 | 60 | 68 | 23 | 153 | 53 |
| MN - No Nuclear | 18 | 40 | 19 | 126 | 53 | 94 | 23 | 21 | 18 | 39 | 16 | 1 | 136 | 28 | 42 | 77 | 23 | 29 | 72 | 62 | 144 |
| MN - Offshore Wind | 18 | 40 | 23 | 135 | 38 | 49 | 7 | 37 | 18 | 30 | 24 | 1 | 136 | 47 | 42 | 72 | 24 | 28 | 79 | 61 | 43 |
| LN Base | 18 | 40 | 25 | 138 | 53 | 34 | 13 | 36 | 18 | 31 | 16 | 21 | 85 | 76 | 43 | 50 | 46 | 33 | 72 | 118 | 88 |
| HH Base | 18 | 40 | 23 | 134 | 45 | 34 | 13 | 36 | 2 | 50 | 16 | 12 | 105 | 25 | 39 | 104 | 50 | 19 | 81 | 28 | 65 |
| SC Base | 18 | 40 | 13 | 27 | 115 | 21 | 82 | 26 | 2 | 46 | 16 | 1 | 32 | 91 | 94 | 30 | 67 | 27 | 77 | 27 | 40 |

## Table 12.20 – Utility Scale Wind[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | 486 | 804 | - | - | 451 | - | - | 3 | 2,327 | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | 1,417 | 594 | - | - | 451 | - | - | 3 | 2,954 | 187 | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | 1,077 | 594 | 153 | 78 | 350 | - | - | 2 | 3,132 | 178 | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | 439 | 970 | 602 | - | - | - | - | - | 273 | 2,634 | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | 422 | 834 | - | - | 412 | - | - | 199 | 1,374 | 616 | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | 452 | 792 | - | 200 | - | 41 | - | 270 | 864 | 1,126 | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | 594 | - | - | - | - | - | 3 | 3,015 | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | 1,187 | 721 | 975 | 233 | - | 451 | - | - | 3 | 2,492 | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | 1,417 | - | 594 | - | - | 451 | - | - | 297 | 3,236 | 152 | - | - | - | - | - | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.21 – Small Scale Wind[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | 380 | 505 | 4 | 85 | - | - | - | 246 | 4 | 37 | 9 | - | - | 236 | 802 | - | - |
| MR Base | - | - | - | - | - | 745 | - | 60 | 52 | - | - | 300 | 98 | 9 | 9 | - | - | 552 | 28 | 414 | 40 |
| MN - No Coal Post 2032 | - | - | - | - | 380 | 505 | 4 | 85 | - | - | - | 246 | 4 | 37 | 9 | - | - | - | - | 176 | 660 |
| MN - No CCS | - | - | - | - | 380 | 505 | 4 | 85 | - | - | - | 246 | 4 | 37 | 9 | - | - | - | - | 176 | 660 |
| MN - No Nuclear | - | - | - | - | - | 246 | 7 | - | - | - | 21 | 207 | 111 | 17 | 9 | - | - | - | - | 105 | 211 |
| MN - Offshore Wind | - | - | - | - | - | 113 | - | - | - | - | - | - | - | - | - | - | - | 79 | 1 | - | - |
| LN Base | - | - | - | - | 500 | 349 | 34 | 26 | - | 29 | 29 | 29 | 41 | 33 | 9 | 109 | - | - | - | 194 | 660 |
| HH Base | - | - | - | - | 133 | 876 | 89 | - | - | - | 14 | 172 | 76 | 75 | 49 | - | 402 | 486 | 120 | 125 | 37 |
| SC Base | - | - | 20 | - | 302 | 616 | 35 | 89 | 1 | - | 8 | 215 | 32 | 103 | 119 | - | - | 875 | 92 | - | 454 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.22 – Utility Solar[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | 245 | 182 | - | 848 | 896 | 805 | 49 | 5 | - | 2,221 | 4 | - | - | - | 237 | - | - | - | - |
| MR Base | - | - | 137 | 107 | - | 505 | 794 | 1,081 | 522 | 1 | - | 2,736 | 2 | 406 | - | - | 237 | - | - | - | - |
| MN - No Coal Post 2032 | - | - | 245 | 182 | - | 848 | 896 | 805 | 87 | 5 | 480 | 4,291 | 4 | - | - | - | 237 | - | - | - | - |
| MN - No CCS | - | - | 245 | 182 | - | 848 | 896 | 805 | 567 | 5 | - | 4,291 | 2 | - | - | - | 237 | - | - | - | - |
| MN - No Nuclear | - | - | 290 | 237 | - | 44 | 181 | 451 | 521 | 2 | 2,079 | 2,103 | 4 | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | 297 | 101 | - | 385 | 411 | 634 | 521 | 4 | - | 405 | 4 | - | - | 670 | - | - | 393 | - | - |
| LN Base | - | - | 136 | 317 | 49 | 683 | 985 | 452 | 522 | 300 | 105 | 1 | 4 | 6 | - | - | 231 | - | - | - | - |
| HH Base | - | - | 419 | 411 | - | 546 | 2,865 | 452 | 4 | 1 | - | 2,648 | 800 | 406 | - | - | 237 | - | - | - | - |
| SC Base | - | - | 336 | 500 | - | 281 | 1,156 | 415 | 55 | 1 | 66 | 3,363 | 1,584 | 564 | 139 | - | 237 | 793 | - | - | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.23 – Small Scale Solar[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | 61 | - | 110 | - | 27 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | 591 | - | 1 | 26 | 17 | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | 731 | 55 | 72 | - | - | 3 | 165 | 54 | 8 | 9 | - | - | - | - | - | 244 |
| LN Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,121 |
| SC Base | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 156 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.24 – Battery Storage [1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | 520 | 1,297 | 116 | - | 39 | - | 416 | 3 | 317 | 176 | - | 11 | 253 | 10 | 81 | 105 | 488 | 257 | 279 | 15 |
| MR Base | - | 520 | 1,135 | 26 | 181 | 390 | 108 | 537 | 37 | 197 | 277 | - | 176 | 341 | 73 | 81 | 79 | 651 | 589 | 639 | 15 |
| MN - No Coal Post 2032 | - | 520 | 1,297 | 116 | - | 19 | 4 | 639 | 12 | 71 | 365 | - | 56 | 602 | 220 | 422 | 128 | 227 | 242 | 411 | 17 |
| MN - No CCS | - | 520 | 1,297 | 16 | 43 | 19 | 4 | 464 | 14 | 242 | 389 | - | 438 | 417 | 65 | 488 | 214 | 214 | 355 | 592 | 15 |
| MN - No Nuclear | - | 520 | 734 | 124 | 318 | 879 | 110 | 317 | 15 | 309 | 148 | - | - | 314 | 14 | 861 | 174 | 95 | 108 | 43 | 96 |
| MN - Offshore Wind | - | 520 | 1,360 | 328 | 220 | 558 | 140 | 69 | 122 | 118 | 47 | - | - | 127 | 10 | 1,067 | 322 | 405 | 313 | 244 | 15 |
| LN Base | - | 520 | 1,235 | 160 | 3 | - | - | 401 | 6 | 242 | 546 | 156 | 368 | 245 | 412 | 863 | 211 | 456 | 380 | 851 | 9 |
| HH Base | - | 520 | 1,133 | 66 | 108 | 347 | 141 | 452 | 141 | 12 | 200 | - | 74 | 50 | 12 | 193 | 136 | 505 | 399 | 276 | 34 |
| SC Base | - | 520 | 1,011 | 98 | - | 708 | 2 | 592 | 91 | 14 | 181 | - | 13 | 313 | 307 | 94 | 393 | 41 | 370 | 695 | 139 |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.25 – Long Duration Storage [1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | 1 | 26 | 62 | 655 | 166 | 22 | 93 | 88 | 67 | - | - | 326 | 466 | 312 | 325 | - | 264 | 332 | 80 |
| MR Base | - | - | - | - | - | 378 | - | - | - | - | - | - | - | 60 | 167 | 496 | 261 | 50 | 108 | 71 | - |
| MN - No Coal Post 2032 | - | - | 1 | 26 | 62 | 655 | 166 | 22 | 93 | 88 | 67 | - | - | 130 | 174 | 634 | 381 | 97 | 277 | 332 | 80 |
| MN - No CCS | - | - | 1 | 26 | 62 | 655 | 166 | 22 | 93 | 88 | 67 | - | - | 130 | 174 | 634 | 381 | 97 | 277 | 332 | 80 |
| MN - No Nuclear | - | - | 251 | 109 | - | 123 | 249 | 97 | - | 258 | 126 | - | 36 | 152 | 120 | 277 | 229 | 246 | 160 | 104 | 33 |
| MN - Offshore Wind | - | - | 45 | 15 | 79 | 166 | - | 31 | - | 339 | 178 | - | - | 382 | 675 | 305 | 206 | 274 | 327 | 362 | 122 |
| LN Base | - | - | 93 | - | 2 | 803 | 151 | 66 | 102 | 58 | - | - | - | 58 | 94 | 554 | 89 | 109 | 257 | 345 | 23 |
| HH Base | - | - | - | - | - | 243 | - | - | - | 86 | 131 | - | 274 | 375 | 106 | 555 | - | - | 135 | 346 | 90 |
| SC Base | - | - | - | - | - | 197 | - | - | - | 103 | 78 | - | 24 | - | 14 | 399 | 130 | 469 | 373 | 108 | - |

[1] Positive values indicate installed capacity in the first full year of operation.

## Table 12.26 – Majority Owned Coal Retirements[1]

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | (220) | - | - | - | (268) | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | (220) | - | - | - | (268) | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

[1] Negative values indicate retirement of coal capacity.

## Table 12.27 – Carbon Capture and Sequestration Selections

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (264) |
| HH Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Table 12.28 – Coal to Gas Conversion Selections

| Study | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
| MN Base | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MR Base | - | 357 | - | - | 205 | 2,397 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Coal Post 2032 | - | 357 | - | - | 205 | 3,097 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No CCS | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - No Nuclear | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MN - Offshore Wind | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LN Base | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| HH Base | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SC Base | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 9 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. As a consequence, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS.

**Table 12.29 – Preferred Portfolio Variant Studies**

| Variant | Description |
|---|---|
| **No CCS** | No coal units are able to select CCS technology |
| **No Nuclear** | No nuclear resources are eligible for selection |
| **No Coal 2032** | All coal must retire or gas convert by January 1, 2032 |
| **Offshore Wind** | Counterfactual to the Preferred Portfolio selection |
| **All Coal End of Life** | Current coal units cannot gas convert OR select CCS |
| **No New Gas** | Proxy gas plants are not eligible for selection |
| **Force All Gas Conversions** | All coal plants that can gas convert, must |
| **No Forward Technology** | Nuclear, Hydrogen and Biodiesel units are not eligible |

Table 12.30 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no $CO_2$) price-policy scenario.

**Table 12.30 – Initial and Variant Cases Under Medium Gas/ Zero $CO_2$**

| | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| Case - MN | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2023-2042 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base MN | 22,930 | 0 | 1 | 220,325 | 66,013 | 5 |
| Integrated No Coal Post 2032 MN | 23,844 | 914 | 4 | 154,979 | 668 | 2 |
| Integrated No CCS MN | 23,199 | 269 | 3 | 218,003 | 63,691 | 4 |
| Integrated Offshore Wind MN | 29,231 | 6,301 | 6 | 216,728 | 62,417 | 3 |
| Integrated No Nuclear MN | 24,295 | 1,365 | 5 | 239,932 | 85,621 | 6 |
| Integrated Base MR | 22,985 | 55 | 2 | 154,311 | 0 | 1 |

Table 12.31 below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero $CO_2$) price-policy scenario.

**Table 12.31 – Initial and Variant Cases Under Low Gas/ Zero $CO_2$**

| Case - LN | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2023-2042 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base LN** | | | | | | |
| Integrated Base MN | 20,981 | 101 | 2 | 215,698 | 38,760 | 5 |
| Integrated No Coal Post 2032 MN | 21,598 | 718 | 4 | 178,027 | 1,089 | 2 |
| Integrated No CCS MN | 21,470 | 589 | 3 | 204,546 | 27,608 | 3 |
| Integrated Offshore Wind MN | 27,395 | 6,515 | 6 | 208,244 | 31,305 | 4 |
| Integrated No Nuclear MN | 22,085 | 1,205 | 5 | 235,603 | 58,664 | 6 |
| Integrated Base MR | 20,880 | 0 | 1 | 176,938 | 0 | 1 |

**The Integrated LN Base case was not able to be evaluated in ST prior to publishing the draft. The comparative data for this table will be provided prior to final publication.

Table 12.32 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high $CO_2$) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

**Table 12.32 – Initial and Variant Cases Under High Gas/ High $CO_2$**

| Case - HH | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2023-2042 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base HH | 25,554 | 0 | 1 | 121,431 | 0 | 1 |
| Integrated Base MN | 27,549 | 1,995 | 5 | 141,740 | 20,308 | 6 |
| Integrated No Coal Post 2032 MN | 27,315 | 1,760 | 3 | 129,468 | 8,037 | 2 |
| Integrated No CCS MN | 27,351 | 1,797 | 4 | 132,543 | 11,111 | 4 |
| Integrated Offshore Wind MN | 33,701 | 8,146 | 7 | 140,389 | 18,957 | 5 |
| Integrated No Nuclear MN | 29,601 | 4,047 | 6 | 147,714 | 26,283 | 7 |
| Integrated Base MR | 26,776 | 1,222 | 2 | 130,846 | 9,414 | 2 |

Table 12.33 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

**Table 12.33 – Initial and Variant Cases Under Medium Gas/ Social Cost of $CO_2$**

| | ST Value | | | CO2 Emissions | | |
|---|---|---|---|---|---|---|
| Case - SC | PVRR ($m) | Change from Lowest Cost Portfolio ($m) | Rank | Total CO2 Emissions, 2023-2042 (Thousand Tons) | Change from Lowest Emission Portfolio | Rank |
| Integrated Base SC | 29,603 | 0 | 1 | 61,102 | 0 | 1 |
| Integrated Base MN | 30,766 | 1,163 | 3 | 68,506 | 7,404 | 5 |
| Integrated No Coal Post 2032 MN | 30,773 | 1,170 | 4 | 62,173 | 1,071 | 3 |
| Integrated No CCS MN | 30,665 | 1,062 | 2 | 61,948 | 847 | 2 |
| Integrated Offshore Wind MN | 36,933 | 7,330 | 6 | 66,925 | 5,823 | 4 |
| Integrated No Nuclear MN | 32,606 | 3,003 | 5 | 71,961 | 10,859 | 6 |

**Initial and Variant Cases Under Medium Gas/ Federal Regulation (MR)**

The only variant cases which would be compliant under the current language in EPA 111(d) are the MR case and the No Coal Post 2032 case. The Base MR portfolio is $807 million less in PVRR than the No Coal Post 2032 portfolio when dispatched under the MR gas and market pricing structure. $CO_2$ emissions are 972 tons higher in the Base MR portfolio than the No Coal post 2032 portfolio.

## Variant Study Analysis

**No CCS Variant**

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were not to be commercially viable at these locations.

Figure 12.15 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Given the lower capacity factor of coal plants without CCS, additional resources are needed over the course of the horizon to generate enough energy to meet retail demand. This results in 1,447 MW of additional wind, 2,588 MW of additional solar and 1,420 MW of additional storage as compared to the integrated MN view.

**Figure 12.13 - Increase/(Decrease) in Proxy Resources with No CCS**

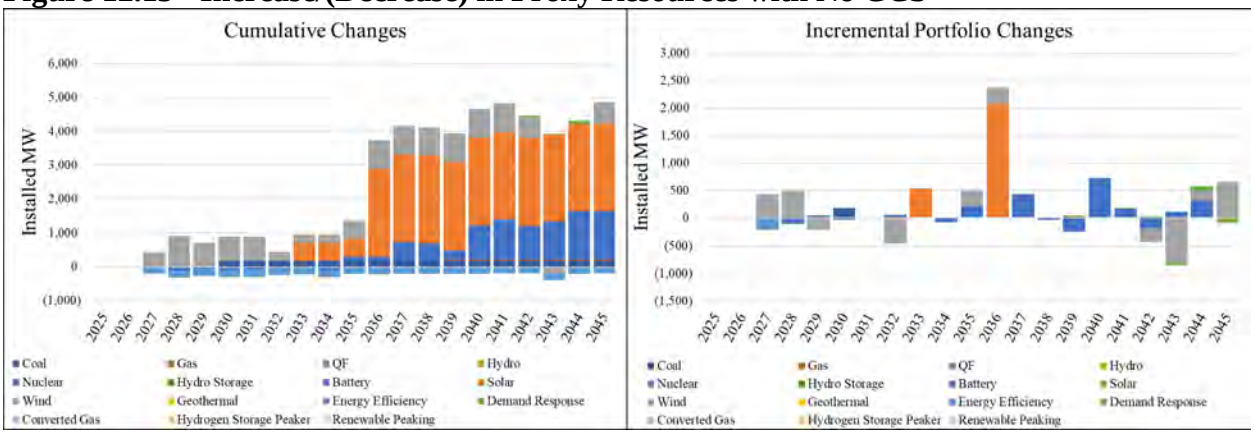
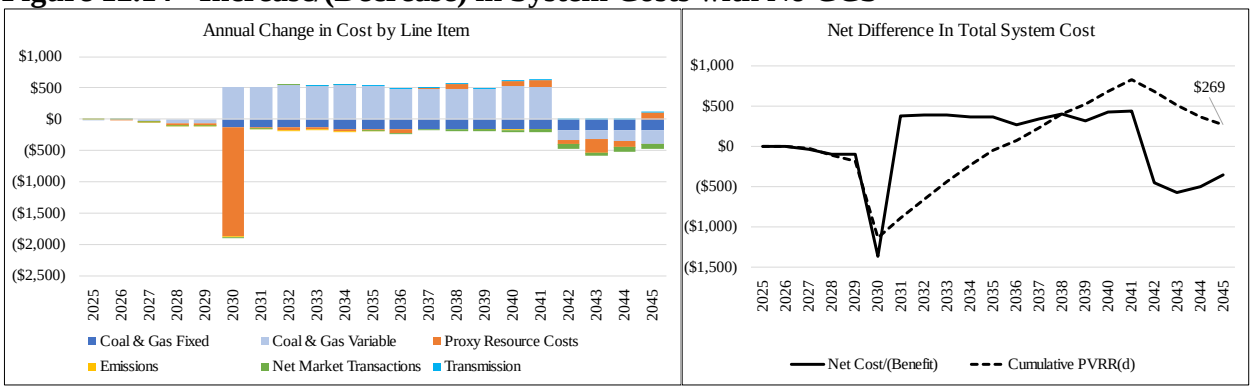



Figure 12.16 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $269 million increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

**Figure 12.14 - Increase/(Decrease) in System Costs with No CCS**




## No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2030. Additionally, this variant does not allow any other nuclear to be selected as a potential replacement of the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the Natrium™ demonstration or other nuclear project prove not to be commercially viable.

Figure 12.17 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Given the currently selected nuclear siting at Naughton, overall portfolio changes are somewhat smaller than

in cases where significant coal changes are tested. The variant case selects 40 MW of new gas peaking resources, an additional 468 MW of energy efficiency, 998 fewer MW of wind which is offset by 1,293 additional MW of solar. Finally, an additional 81 MW of storage is selected.

**Figure 12.15 - Increase/(Decrease) in Proxy Resources with No Nuclear**

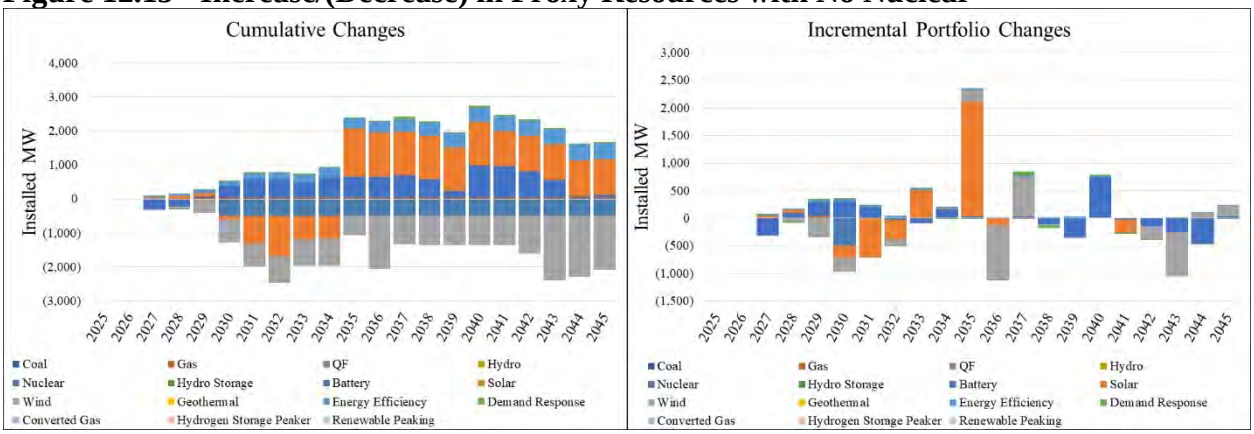
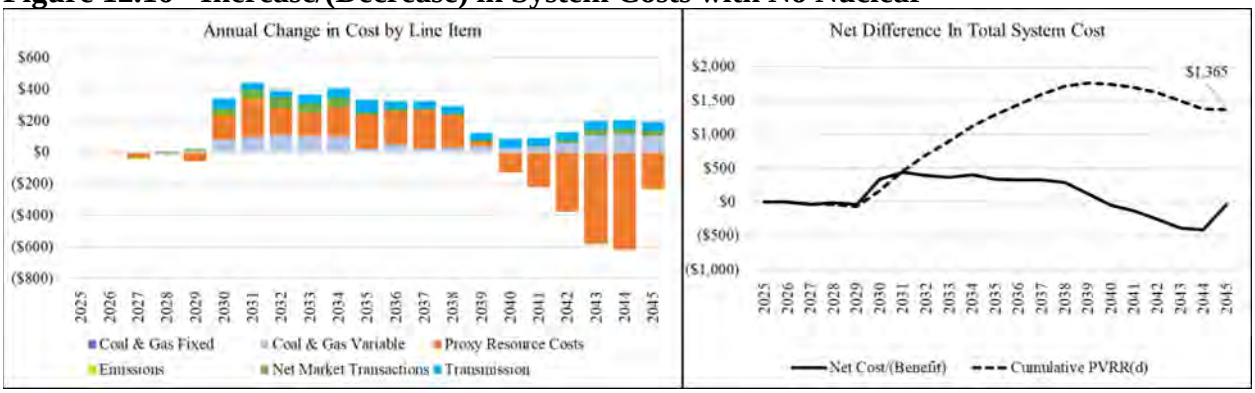



Figure 12.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.365 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.18 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

**Figure 12.16 - Increase/(Decrease) in System Costs with No Nuclear**




**No Coal Post 2032 Variant**

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS.

Figure 12.19 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects new gas peaking resources whereas the integrated MN view does not. Additionally, more solar and wind is selected in the variant, and less long duration storage is partially offset by additional 4-hour storage.

**Figure 12.17 - Increase/(Decrease) in Proxy Resources with No Coal Post 2032**

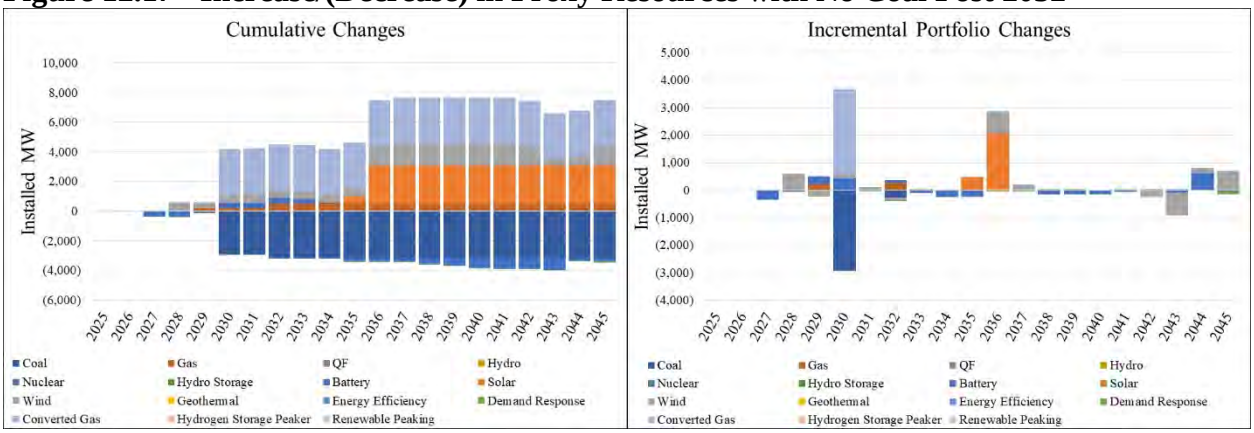
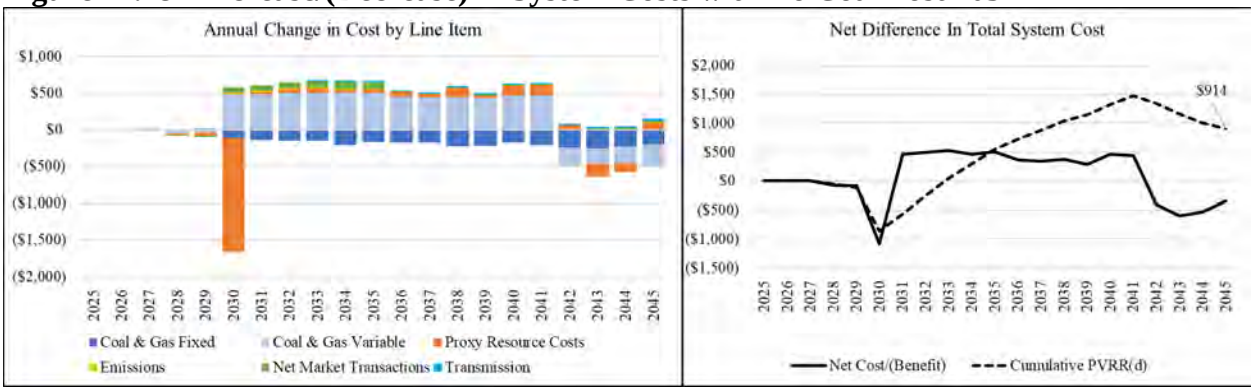



Figure 12.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or gas converted by 2032, the resulting portfolio has a $914 million increase in costs compared to the preferred portfolio.

As seen in Figure 12.20 below, like in the No CCS case, the loss of 45Q tax credits more than offsets the reduced capital cost to install CCS. Additionally, this case has higher levels of market purchases, and additionally has higher proxy resource costs in nearly all years of the study horizon.

**Figure 12.18 - Increase/(Decrease) in System Costs with No Coal Post 2032**



**Force Offshore Wind**

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 12.21 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The higher capacity factor of the offshore wind resource results in 300 MW less utility scale wind being selected in the portfolio compared to the preferred portfolio. Additionally, the portfolio has 1,669 MW less utility scale solar. Less small-scale wind is offset by more small scale solar. For capacity and reliability needs, 1,824 more MW of storage is selected in the offshore wind case, 1,603 MW of which is 4-hour storage. Retirements are the same between the studies.

**Figure 12.19 - Increase/(Decrease) in Proxy Resources with Offshore Wind**

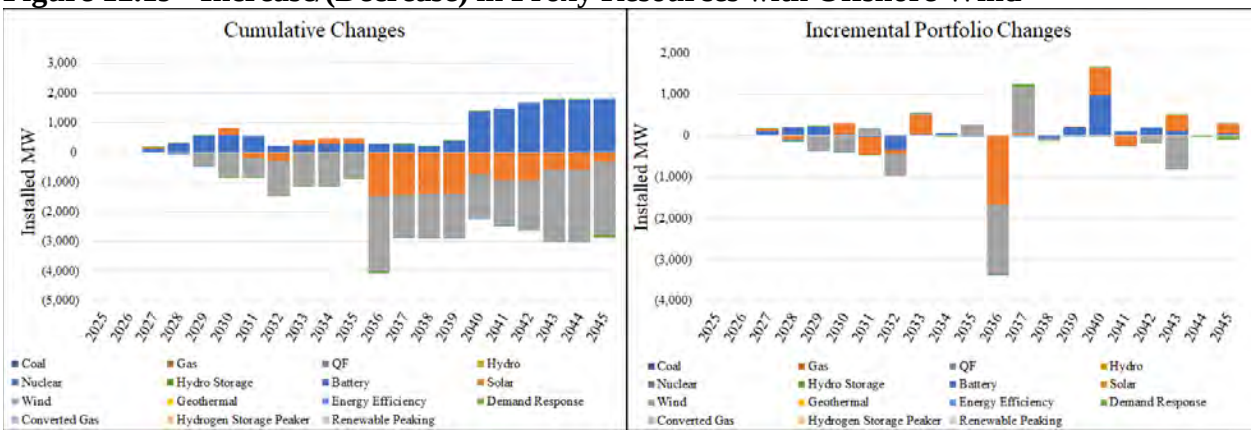
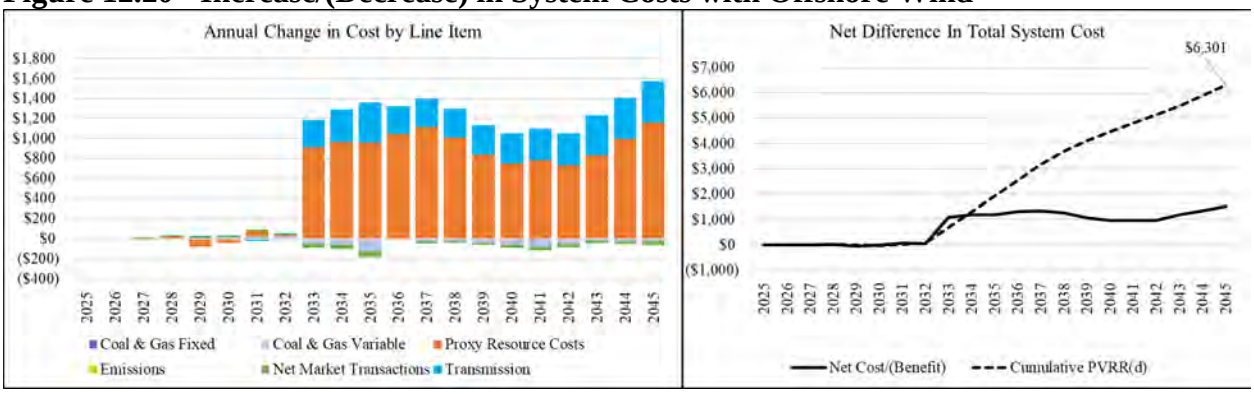



Figure 12.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $6.301 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.22 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

**Figure 12.20 - Increase/(Decrease) in System Costs with Offshore Wind**



# CHAPTER 13 – UTAH ACTION PLAN

## ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

## CHAPTER HIGHLIGHTS

- The Utah 2025 Integrated Resource Plan (IRP) action plan identifies steps, determined when the analysis was conducted, that PacifiCorp would pursue over the next two-to-four years to deliver resources aligned with the Utah preferred portfolio.
- PacifiCorp's Utah 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[2]
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

## Introduction

PacifiCorp's Utah 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The Utah 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp

[1] https://pscdocs.utah.gov/electric/23docs/2303510/3356352303510o9-24-2024.pdf

[2] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the Utah 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the Utah 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the Utah 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

## The Utah 2025 IRP Action Plan

The Utah 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

**Table 10.1 – Utah 2025 IRP Action Plan**

| Action Item | 1. Existing Resource Actions |
|---|---|
| 1a | **Colstrip Units 3 and 4:**<br>• PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030. |
| 1b | **Craig Unit 1:**<br>• PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the Utah 2025 IRP preferred portfolio target exit date of December 31, 2025. |
| 1c | **Naughton Units 1 and 2:**<br>• PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>• PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. |
| 1d | **Carbon Capture and Storage / Low Carbon Portfolio Standard:**<br>• PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. |
| 1e | **Regional Haze Compliance:**<br>• Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. |
| 1f | **Natrium™ Demonstration Project:**<br>• By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. |

| | |
|---|---|
| **1g** | **Ozone Transport Rule Compliance:**<br>• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>• The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments. |
| **1h** | **Natural Gas Emissions Compliance Strategies**<br>• The Utah 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030. |
| **1i** | **Federal Greenhouse Gas Emission Compliance:**<br>• EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues. |
| **1j** | **Dave Johnston Units 1 and 2:**<br>• PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029. |

| Action Item | 2. New Resource Actions |
|---|---|
| 2a | **Customer Preference Request for Proposals:**<br>• PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>• Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025. |
| 2b | **2025 All-Source Request for Proposals:**<br>• PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3]<br>• In light of the differentiated resource needs by jurisdiction identified in the Utah 2025 IRP, scope and targeted resource needs may vary by jurisdiction. |

| Action Item | 3. Transmission Action Items |
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| 3a | **Local Reinforcement Projects**<br>Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids. |
| 3b | **Gateway West Support**<br>Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. |

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

| Action Item | 4. Demand-Side Management (DSM) Actions |
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| 4a | **Energy Efficiency Targets:**<br>• PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.<br>• PacifiCorp will pursue cost-effective energy efficiency resources.<br>• PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year. |

| Action Item | 5. Market Purchases |
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| 5a | **Market Purchases:**<br>• PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:<br>o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.<br>o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.<br>o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions. |

| Action Item | 6. Renewable Energy Credit (REC) Actions |
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| 6a | **Renewable Portfolio Standards (RPS):**<br>• PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>• PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed. |

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| **6b** | **Renewable Energy Credit Sales:**<br>• Maximize the sale of RECs that are not required to meet state RPS compliance obligations. |

## Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the Utah 2025 IRP action plan. The status for all action items from the Utah 2025 IRP is summarized in Table 10.2.

**Table 10.2 – 2023 IRP Action Plan Status Update**

| Action Item | 1. Existing Resource Actions | Status |
|---|---|---|
| **1a** | **Colstrip Units 3 and 4:**<br>• PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030. | • PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project. |
| **1b** | **Craig Unit 1:**<br>• PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025. | • PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project. |
| **1c** | **Naughton Units 1 and 2 Gas Conversion:**<br>• PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026.<br>• PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission. | • PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas.<br>• Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025. |

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| **1d** | **Jim Bridger Units 1 and 2 Gas Conversion:**<br>• PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by the end of 2023.<br>• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. | • PacifiCorp received an approval order on December 7, 2023 from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas.<br>• PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023.<br>• Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024. |
| **1e** | **Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:**<br>• PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023.<br>• PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024. | • PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023.<br>• PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200. |
| **1f** | **Regional Haze Compliance:**<br>• Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective. | • Utah's first planning period disputes have been resolved.<br>• Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date.<br>• Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. |

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| | | • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to the second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date. |
| **1g** | **<u>Natrium™ Demonstration Project:</u>**<br>• PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable.<br>• By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project.<br>• By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders.<br>PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501. | • PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the Natrium™ project and expects to finalize these arrangements by the end of 2025. |
| **1h** | **<u>Ozone Transport Rule Compliance:</u>**<br>• PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP.<br>• PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. | • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements.<br>• The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. |

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| | • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023. | |
| **Action Item** | **2. New Resource Actions** | **Status** |
| **2a** | **<u>Customer Preference Request for Proposals:</u>**<br>• PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window.<br>• Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window. | PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024. |
| **2b** | **<u>2025 All-Source Request for Proposals:</u>**<br>• PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 | The Utah 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term. |

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| | IRP preferred portfolio that can achieve commercial operations by the end of December 2030.<br>• In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator.<br>• In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions.<br>• In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market.<br>• In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on the final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable.<br>• By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.<br>• Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier. | |
| **2c** | **<u>2022 All-Source Request for Proposals:</u>**<br>• In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027. | • PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities. |

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| | • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on the final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and<br>• By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.<br>• Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier. | • EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource procurement needs coming out of the 2022 All-Source Request for Proposals.<br>• PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals. |
| **Action Item** | 3. **Transmission Action Items** | **Status** |
| **3a** | **Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):**<br>• In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service. | The Energy Gateway South transmission project is in-service. |
| **3b** | **Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):**<br>• In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service. | The Energy Gateway West Sub-Segment D1 transmission project is in-service. |
| **3c** | **Boardman-to-Hemingway (500 kV transmission line):**<br>• Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement.<br>• Continue to participate in the development and negotiations of the construction agreement. | PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date. |

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| | • Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date.<br>• Continue negotiations for plan of service post B2H for parties to the permitting agreement. | |
| **3d** | Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids | Reinforcements have been identified. A final assessment of upgrades is pending signed agreements. |
| **3e** | Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade. | PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment. |

| Action Item | 4. **Demand-Side Management (DSM) Actions** | Status |
|---|---|---|
| **4a** | **<u>Energy Efficiency Targets:</u>**<br>PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP. | • PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and is on track to achieve its 2024 Class 2 DSM target.<br>• PacifiCorp has launched a number of new demand response programs in 2022 and 2023. Additionally, the company is currently expanding its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023 incremental |

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| | | capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs. |
| **Action Item** | 5. **Market Purchases** | **Status** |
| **5a** | **Market Purchases:**<br>• Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.<br>• Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.<br>• Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions. | Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions. |

| Action Item | 6. **Renewable Energy Credit (REC) Actions** | Status |
|---|---|---|
| **6a** | **Renewable Portfolio Standards (RPS):**<br>• PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.<br>• As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed. | PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed. |
| **6b** | **Renewable Energy Credit Sales:**<br>• Maximize the sale of RECs that are not required to meet state RPS compliance obligations. | PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations |

# Acquisition Path Analysis

## Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the Utah 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the Utah preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the Utah 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, $CO_2$ policy also influences resource selections in the Utah 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

## Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[4] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[4] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

A full acquisition path analysis relevant to all jurisdictions is presented the Chapter 10 (Action Plan), Table 10.3.

## Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable and resilient grid operations. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

## IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the Utah 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

## Resource Procurement Strategy

To acquire resources outlined in the 2023 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2023 IRP action plan.

### Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFP to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, define specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

### Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

### Demand-Side Management[5]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on the size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings, and has continued Wattsmart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

[5] Class 1 DSM is most commonly referred to as "demand response" in the 2023 IRP; Class 2 DSM is most commonly referred to as "energy efficiency". Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

## Small Scale Renewable Energy Supply

In order to fulfill Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is addressed in PacifiCorp's 2023 Oregon Clean Energy Plan.

## Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. While the level of imputation associated with long-term contracts is expected to be lower than the debt associated with owned resources, it still may affect PacifiCorp's credit ratios and credit rating.

## Managing Carbon Risk for Existing Plants

$CO_2$ reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower $CO_2$ emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by $CO_2$ reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal

frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a $CO_2$ tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as $CO_2$ capture with sequestration. As mentioned above, plant $CO_2$ emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

## Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

### Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

## Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

## Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

## Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

## Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

### Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

### Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

### Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of $CO_2$ policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit HH: SPP, *SPP Reliability Plan* (June 2, 2025)

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# SPP RELIABILITY PLAN

**0820EXT00108**

**Business Owner:** Derek Hawkins
**Effective:** 06/02/2025
**Revised:** 06/2/2025
**Version:** 8.0

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|---|---|---|
| **Approved By:** | Brian Strickland | Digitally signed by Brian Strickland<br>Date: 2025.06.11 13:41:29 -05'00' |
| SME Signature (Brian Strickland) | | Date |

| | | |
|---|---|---|
| **Approved By:** | Derek Hawkins | Digitally signed by Derek Hawkins<br>Date: 2025.06.11 13:42:26 -05'00' |
| Business Owner Signature | | Date |

# Revision History

| Author | Version | Revision Date | Effective Date | Description |
|---|---|---|---|---|
| ORWG | 1.0 | 6/1/05 | | Complete re-write to align with revised NERC Policy 9 as approved by NERC 06/15/04. |
| | | 6/15/05 | | Per NERC ORS request, removed Appendix B – Reliability Assessment Process and Procedure. |
| | | 1/11/06 | | Added CLECO to the plan. |
| | | 1/26/06 | | Added Constellation Balancing Authorities BCA, CNWY, DENL, DERS, PUPP, and WMUC to the plan. |
| | | 1/27/06 | | Updated to reflect changes in SPP processes and procedures after the SPP EIS Market is implemented. |
| | | 2/9/06 | | Made necessary changes to conform with NERC functional model terminology present in existing reliability standards. |
| | | 9/8/06 | | Added LAGN to the plan with an effective date of November 1, 2006 |
| | | 12/5/06 | | Added Constellation Balancing Authority BUBA |
| | | 1/1/09 | | Changes consistent with Criteria 12.3. Corrected Batesville Generating Station acronym from BCA to BBA. Added Missouri Public Service (MPS) to footprint. |
| | | 4/1/09 | | Added Nebraska entities – LES, NPPD and OPPD |
| | | 10/1/09 | | Added Constellation Balancing Authorities OMLP and PLUM |
| | | 4/1/10 | | DENL Balancing Authority moved from operation by Constellation to operation by NRG and changing DENL to NLR |
| | | 1/1/11 | | CNWY and WMUC Balancing Authority moved from operation by Constellation to operation by NRG and changed from CNWY to CWAY and from WMUC to WMU |
| | | 2-15-11 | | City Utilities of Springfield (SPRM) becoming a stand-alone Balancing Authority Areas instead of a TOP imbedded inside the SPA Balancing Authority Areas. |
| | | 4/11/12 | | Added Brazos Electric to list of Balancing Authorities. Updated map to reflect addition. Changed “OPS1” application in reference to outage scheduling to “CROW” application reference. Clarified the RTCA and monitored elements by voltage in sections C.4. and E1. Noted the primary and BUCC location changes in 2012 in section I. |

| Author | Version | Revision Date | Effective Date | Description |
|---|---|---|---|---|
| | | 6/1/13 | | Transferred the southern reliability members from SPP to MISO (with exception of the CECD entities) per Entergy move to MISO |
| | | 12/19/13 | | Removal of the CECD entities from the SPP Reliability footprint. Changed cover page date to Dec 19, 2013. |
| | | 3/1/14 | | Replaced "EIS" with "Integrated", removed OPS1 references, replaced PowerWorld with E-terravision, removed member map, and changed list of BA/TOPs to reflect new consolidated BA (SPP BA). |
| | | 6/1/15 | | Added the IS entities of WAPA, Corn Belt to the TOP list within the Introduction and the SPP Reliability Areas. Changed WECC references to PEAK Reliability. |
| | 2.0 | 4/21/16 | | Changes made due to overall review, and to correct studies, update tools, Operating Criteria changes, DC tie additions, reduce redundancy of sections and Market constraint management. |
| Terry Oxandale | 3.0 | 4/30/2019 | 4/30/2019 | Modified for SPP RC for Western Interconnect effective 12/3/2019. Added changes in RE, additional TOPs in Appendix A, and included aspects of the Western Interconnect not included in the current Eastern Interconnect practices. Converted to current template and assigned new Operations document ID 0820PCS00108. |
| Brian Strickland, Derek Hawkins | 3.1 | 11/20/2019 | 11/20/2019 | Updated with additional information on loss of necessary applications, weather, Cyber Attack, and SPS/RAS. Updated AZPS (under CAISO RC) to AEPC (under SPP RC). Updated for clarifications per RCRT review. Deleted Gila River Power (GRMA) from Appendix A table being they are not a TOP per Bryan Wood. |
| Brian Strickland, Yasser Bahbaz | 3.2 | 2/10/2021 | 4/1/2021 | Added GRID effective 4/1/2021 to "BAs and TOPs in SPP RC Areas" section in Appendix A. Also updated file name of documents referenced in Appendix B. |
| Brian Strickland | 4.0 | 1/07/2022 | | Added language to GMD to address monitor responsibilities and added a section on voltage. Changed business owner and SME per B. Wood. |
| Julie Gerush, Brian Strickland | 5.0 | 04/12/2023 | 04/12/2023 | Comments addressed from Operations review. Changes to accommodate changes to IDC. Updated cover pages. |

| Author | Version | Revision Date | Effective Date | Description |
|---|---|---|---|---|
| Heather Harris, Brian Strickland | 6.0 | 04/01/2024 | 04/01/2024 | Removed Appendix B (RC Related procedures), updated to identify no delegation of task or actions requested for adjacent RCs, minor language changes to mirror requirement language. Removed GRIF under entities due to merger with GRID. Added language for SOL/IROL communication and general cleanup Changed document ID. |
| Hayden Johnson | 7.0 | 01/31/2025 | 02/01/2025 | Added First Light Energy (BNBA) to the list of BAs/TOPs in the Appendix. |
| Hayden Johnson | 8.0 | 06/02/2025 | 06/02/2025 | Removed New Harquahala Generation Station (HGMA) from the list of BAs/TOPs in the Appendix. |

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## Introduction

The North American Electric Reliability Corporation (NERC) delegates its authority to monitor and enforce compliance with NERC Reliability Standards to the Regional Entities (RE). The RE carries out their reliability activities with the Registered Entities for their reliability region. Southwest Power Pool (SPP) is recognized as the Reliability Coordinator (RC) for all Transmission Operators (TOPs) and Balancing Authorities (BAs), listed in **Appendix A**, in both the Eastern and Western Interconnections.

SPP RC is responsible for the bulk transmission reliability and power supply reliability within its RC Areas. Bulk transmission reliability functions include assessment of real-time and next day operating conditions, congestion management, coordination of transmission and generation outages and instructing curtailment of transactions and/or load. SPP RCs use a risk-based approach to communicating actual and potential SOL exceedances with impacted TOPs, as described in SPP's Reliability Coordinator Area System Operating Limit Methodology and Reliability Coordinator Area System Operating Limit Methodology Western Interconnection. Power supply reliability entails monitoring BA Areas performance and coordinating BAs and TOPs actions, including instructions, for load curtailment, generation and transmission actions, and adjustments to voltage schedules in situations where the system is in jeopardy. SPP RC procedures and policies are consistent with those of NERC.

Operating agreements are in place to facilitate communication, notification, exchange of information, and coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.

SPP RC communication mediums include phone, the SPP Reliability Communications Tool (R-Comm), the Reliability Coordinator Information System (RCIS), email, NERC Hotline, cellular phones, satellite phones, etc.

**NOTE:** Unless explicitly defined, any reference to "RC" is applicable to both East and West.

## A. Responsibility and Authority

1. SPP has a wide-area view, operating tools, processes, procedures, authority and responsibility for the reliable operation of the Bulk Electric System (BES) within the SPP RC Areas in accordance with NERC Reliability Standards including applicable regional variances, the SPP Membership Agreement, SPP Required Data Specification (RDS), and SPP Reliability Customer agreements. These executed agreements are posted on the SPP website under SPP Documents & Filings/Governing.

    1.1. The SPP RC has a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and

real-time conditions. More details are provided in appropriate sections of this document.

1.2. The executed agreements give the SPP RC clear decision-making authority to act and instruct actions to be taken by the SPP RC Members and Reliability Customers to preserve the integrity and reliability of the BES. SPP's responsibilities and authorities, as well as its RC members' and customers' responsibilities are clearly defined in SPP's governing documentation.

2. SPP acts first and foremost in the best interest of the BES before that of any other entity. This expectation is clearly identified in the SPP Membership and Reliability Customer agreements, and in the job description of the SPP personnel acting in the role of the RC.

3. Per the SPP RC Member and Reliability Customer agreements, the BAs, TOPs, and other operating entities in the SPP RC Areas (i.e. West and East RC Areas) shall carry out required emergency actions as instructed by the SPP RC, including the shedding of firm load if required, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. In those cases, SPP RC Members or Reliability Customers must immediately inform the SPP RC of the inability to perform the operating instruction.

4. Weather-related event is to be determined in advance, based on weather evaluations, storm information, next day studies, etc., for action to be taken by SPP RC as necessary. The evaluation and coordination of analysis information may lead to issuing a Weather Advisory or Conservative Operations. In a coordinated effort, SPP has a process to exchange information related to weather events where SPP or a portion of SPP expects temperatures at a level that is of concern, or where tornado, ice storm, or high wind might be forecasted. Weather Advisories may be issued to prepare personnel and facilities for expected extreme weather conditions.

   4.1 For the Western Interconnection, SPP has a process to exchange information related to potential reliability impacted weather events, including utilizing R-Comm, emails, satellite phones, etc.

5. SPP Information Technology (IT) group maintains an awareness and level of protection from Cyber Attacks. SPP IT group has a process to determine if and when notifications should be made to Operations staff to increase awareness of potential cyber activities. In the event that Operations suspects or detects a Cyber Attack first, they will follow the process in accordance with the SPP Sabotage Procedure to notify the necessary parties.

6. In the event of the loss of a necessary application, SPP shall notify neighboring RCs, BAs, and TOPs to monitor the SPP RC Areas footprint when necessary.

## B. Responsibilities – Delegation of Tasks

The SPP RC has not delegated any RC tasks. Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

## C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) during the real-time and next day operating horizons for the SPP RC Areas including additional thermal, voltage and stability-related analysis as necessary. SPP will communicate and coordinate the results of its reliability assessments with those performed by the SPP RC Members and Reliability Customers, to ensure that any potential or actual SOL exceedances are properly identified and reported. SPP models a sufficient wide-area view to ensure properly coordinated operations with neighboring RCs. SPP will share its Operational Planning Analysis (OPA) via its secure FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas, and does so via documented methodologies. As part of the daily OPA and/or RTA, SPP highlights additional potential SOLs. That list of potential SOLs and the existing list of SOLs are screened for potential IROL criteria. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in cascading outages or widespread voltage problems, unless there are studies or system knowledge that the SOL is not an IROL. Additionally, when temporary constraints are defined for various operating circumstances identified through OPA and/or RTA, this process is performed to verify if an IROL exists. SPP disseminates IROL information within its RC Areas and with neighboring RCs.

3. SPP ensures that SPP RC Members and Reliability Customers operate to prevent the likelihood that a disturbance, action or non-action in the SPP RC Areas will result in an SOL or IROL exceedance in another entity of the Interconnection. SPP's RC Members and Reliability Customers are required to adhere to NERC Reliability Standards. SPP is required by its seams agreements with its neighbors to coordinate maintenance outages in such a way that impacts on the other systems' reliability are minimized. SPP performs OPA on a daily basis for the next day. If a potential SOL or IROL exceedance is observed on a neighboring party's system, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan, if one does not already exist. In instances where there are differences in operating limits derived by SPP and its neighbors or between SPP entities, SPP will operate to the most conservative result until the reasons for these differences can be identified and an agreement is reached.

4. SPP ensures that its RC Members and Reliability Customers are always operating under known and studied conditions and ensures that they reassess and re-posture their systems following contingency events within 30 minutes. SPP performs next day OPA pursuant to the Reliability Assessment Process Overview. These analyses are performed for each day. These analysis model peak conditions for the day being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. SPP performs an N-1 contingency analysis monitoring the post-contingency flow of both SPP and neighboring system facilities. If a potential SOL or IROL exceedance is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan if one does not already exist.

   SPP performs a next-day assessment of capacity and adequacy for each hour of the day, as well as a next-hour assessment of capacity and adequacy on an hourly basis. These analyses model peak conditions for the day/hour being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. If a capacity issue is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan.

   SPP monitors, in real-time, all facilities considered critical. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at the facility ratings, SOL and IROL levels. SPP tracks real-time and applicable post-contingency flows on all constraints and alarms when applicable SOLs and IROLs are approaching the limit or are exceeded. Additionally, when any identified IROL is exceeded in real-time, an email notification of the exceedance is sent to operations management and engineering staff to initiate post-event analysis.

   SPP also uses a State-Estimator solution to run its Real-Time Contingency Analysis (RTCA) application at least every 6 minutes. SPP has defined all branches and transformers with low side voltages of 115 kV and higher (with some 69kV) within the SPP RC Areas and all branches and transformers with low side voltages of 230 kV and higher within the first-tier BA Areas as contingencies in RTCA. SPP monitors the post-contingency flow on all SPP branches and transformers with low side voltages of 115kV and higher. Alarms are triggered if that flow exceeds the emergency rating of the branch or transformer. Additionally, SPP monitors post-contingency flow on all branches and transformers with low side voltages of 230 kV and higher within neighboring systems as well as selected lower voltage facilities within neighboring systems that are known to be impacted by an SPP contingency. The RC receives alarms for any RTCA exceedance.

5. The SPP RTO acts as the Transmission Service Provider (TSP) for all Transmission Owners in the Eastern Interconnection, subject to the SPP Tariff. For these entities,

SPP uses Flowgates as proxies for transmission limitations in the determination of ATC. The same Flowgates monitored in real-time by the SPP RC and their associated SOLs are also incorporated in the models used by SPP to calculate ATC and administer its OATT. SPP limits sales of transmission service to the SOLs of all identified Flowgates. When a need for a new Flowgate is determined by the SPP RC, the new Flowgate is included in the models used by the SPP TSP for calculation of ATC. These Flowgates are posted on the SPP OASIS.

5.1 SPP is not the TSP in the Western Interconnection, with the exception of WAUW.

6. SPP communicates reliability Operating Instructions in a clear, concise, and definitive manner. Per SPP RC procedures, the SPP RC requires the recipient to repeat back any reliability Operating Instructions communicated by the SPP RC. Proper communications protocols are included in Operator training provided by SPP.

## D. Next Day Operations

1. SPP performs an OPA to identify potential SOL and IROL exceedances pursuant to the Daily Reliability Assessment Procedure. These analyses are performed daily with the exception of the weekend and holiday analyses being performed on the previous Friday, or day prior to the holiday. SPP's day-ahead reliability assessment consists of off-line PSS/E studies of the modeled system conducted by the Operations Engineering staff. Contingency-based analyses are conducted daily, which include Remedial Action Schemes (RAS). In these contingency analyses, at a minimum, SPP includes BES facilities in SPP and first-tier area above 100 kV as contingencies, and monitors facilities above 100 kV. SPP will include other facilities identified with impact to BES or with significant risk to the BES. SPP also runs a 7-day contingency analysis to review upcoming operating conditions over the next week for the Eastern Interconnection. Planned transmission and generation outages within the SPP RC Areas are coordinated with adjacent RCs. Outages external to the SPP RC Areas are obtained from neighboring RCs. Peak conditions are modeled using anticipated generation dispatch to support the forecasted load plus expected scheduled net interchange.

    1.1 If, in the next day OPA, parallel flows from the SPP RC Areas are observed as causing a potential problem on a neighboring system, SPP will contact the neighboring RC and coordinate to determine if the problem could result in an SOL or IROL exceedance. If it is agreed that an exceedance could occur, SPP will coordinate with the neighboring RC to develop an appropriate mitigation plan, if one does not already exist. The mitigation plan will identify appropriate actions to be taken to prevent the exceedance from materializing which may include creation of appropriate constraints to be monitored, commitment of appropriate generation capacity, reconfiguration of the transmission system, or re-dispatch of generation as well as actions to be taken in the event the

exceedance materializes in real-time, including identifying potential transmission system reconfigurations, generation that can be re-dispatched, schedules that can be curtailed, and, if necessary, load that can be shed.

2. SPP receives operating information, such as transmission and generation facility maintenance schedules, tap settings, and generation resource plans, required for performing an OPA from responsible SPP RC Members and Reliability Customers. The applicable SPP RDS requires SPP RC Members and Reliability Customers to submit the necessary data to SPP. SPP receives similar information from its neighbors. SPP uses load forecast, generation forecast, and/or tag data as its basis for incorporating Interchange Transactions into the OPA.

3. SPP shares the results of its OPA, when conditions warrant, or upon request, with other RCs. SPP also posts the results of its analyses via its secured FTP site for appropriate SPP RC Members, Reliability Customers, and neighboring RCs. If the results of the OPA indicate potential reliability problems and efforts outlined in (4.) below do not resolve the potential condition, the SPP RC issues the appropriate alerts via the RCIS.

4. The SPP RC initiates conference calls, or other appropriate communications, such as R-Comm, as necessary when conditions revealed by the OPA warrant. Conditions that warrant communications with other RCs include potential IROL exceedances determined as described in part 1.1 of this section and capacity deficiencies that could result in shedding of firm load.

## E. Current Day Operations

1. SPP monitors facilities within the SPP RC Areas and adjacent RC Areas to ensure determination of potential SOL and IROL exceedances.

   1.1 SPP will make reasonable efforts to provide notice to a neighboring RC if SPP identifies a potential reliability problem in that RC's Areas. If both parties agree that a reliability problem exists, SPP will coordinate with its neighboring RCs any actions required to mitigate the situation. In the event that all parties cannot agree on the reliability issue, SPP will follow the most conservative approach. This coordination may include evaluation of the impact of maintenance and forced outages on the situation, implementation of existing emergency procedures or operating guides, reconfiguration of the transmission system, curtailment of point-to-point transactions, re-dispatch of generation, and load shedding.

2. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at both SOL and applicable IROL levels. SPP uses constraint monitoring applications that track post-contingency flows on all constraints and alarms as applicable SOLs

and IROLs are approached and/or exceeded. Post-contingency flows on constraints are calculated using real-time flows and Line Outage Distribution Factors (LODFs) that are updated to reflect current system topography.

3. SPP monitors the necessary RC Area's parameters to ensure it is continuously aware of conditions within the SPP RC Areas.

   3.1. SPP monitors the status of BES elements using an EMS complete with State Estimator, Alarming, Real-Time Contingency Analysis, and Power Flow applications. SPP receives the data necessary to maintain the EMS from its RC Members and Reliability Customers in accordance with applicable SPP RDS.

   3.2. The SPP EMS model represents the SPP RC Areas, neighboring BA Areas and other portions of the Eastern and Western Interconnection. For the Eastern Interconnection, SPP's RC Area represents approximately one-third of the SPP EMS network model of Eastern Interconnection facilities. The EMS uses near real-time measurements received from these same entities via ICCP.

      3.2.1. For the Western Interconnection, SPP maintains a full model referenced from the Western Interconnection-wide Model (WIM) consistent with the Western Interconnection Modeling and Monitoring Methodology.

   3.3. SPP monitors, in real-time, pre-contingent and anticipated post-contingent element conditions. This is achieved through the EMS and constraint monitoring tools which utilize real-time Line Outage Distribution Factors based on the latest system topology.

   3.4. SPP monitors real-time flows and statuses of facilities 100 kV and above and select lower voltage facilities in the Eastern Interconnection. Contingencies of facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are studied. The post-contingent flow on facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are monitored.

      3.4.1. For the Western Interconnection, the monitoring of facilities is consistent with the Western Interconnection Modeling and Monitoring Methodology agreed upon according to applicable NERC standards.

   3.5. SPP monitors real and reactive reserves. SPP receives real-time operating reserves data from its RC Members and Reliability Customers, and compares this data to the operating reserves required. SPP monitors and displays the reactive output of generators within the SPP RC Areas as well as the remaining reactive capability by BA Area. SPP receives real-time voltages on critical buses

which alarm the RC when a voltage limit is exceeded. SPP will contact the appropriate TOP or BA as necessary to develop mitigation plans. SPP RC makes all reasonable efforts to provide notification and coordination of actions that may impact adjacent RC Areas for voltage control, including coordination of reactive resources.

3.6. SPP monitors voltage points based upon a ±5% tolerance around nominal voltage. This tolerance may vary per TOP and for nuclear power stations. When a high or low voltage alarm is received from the EMS system indicating limit violations, SPP will coordinate with the affected TOP to determine if the indicated voltage is correct and verify the TOP's voltage limits for that particular area. SPP will assist the affected TOP in developing a course of action to address undesirable voltage conditions including verifying and changing status of static reactive devices, reconfiguration, coordinating resource commitments, establish power transfer limits and re-dispatch as appropriate, etc.

3.7. The SPP RTO within the Eastern Interconnection monitors capacity and adequacy conditions through the SPP Reserve Sharing System (RSG) and market applications. SPP also receives resource plan information for all resources participating in the SPP Integrated Marketplace (Eastern Interconnection). This information contains data for each resource for each hour of a 7-day horizon beginning with the current day and is updated as necessary throughout the day. SPP will use this and other system information to perform hourly assessments of capacity and adequacy for the next hour.

3.7.1. For the Western Interconnection, SPP West RC will monitor capacity and adequacy conditions utilizing applicable RSG and BA submitted data as documented in the required data specifications.

3.8. SPP monitors current ACE and frequency in real-time for all BA Areas in the SPP RC Areas using the real-time data sent by the BAs through ICCP pursuant to applicable SPP RDS. This information is displayed to the SPP RC constantly.

3.9. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external generation to load (GTL) and transactions.

3.10. SPP receives and reviews resource plans and generation schedules from its Reliability Customers.

3.11. SPP monitors planned and unplanned transmission and generation outages. SPP's RC Members and Reliability Customers are required to submit all generator and transmission outages. Timing requirements and approval

procedures are documented in the applicable SPP Outage Coordination Methodology and applicable SPP RDS. The generator and transmission outages are sent to the Outage Scheduler database of the EMS system and used by the State Estimator and RTCA if the real-time measurements of the facility do not contradict with the submitted outage. The SPP RC Operators are constantly verifying the submitted outage data using State Estimator displays and its alarming application. They contact the appropriate SPP RC Member or Reliability Customer if a scheduled outage does not materialize in real-time as planned or if a line, transformer or unit trips without having a scheduled outage.

SPP utilizes graphical display systems designed to increase SPP RC situational awareness of the SPP RC Areas. The systems use near real-time and/or EMS data to provide a wide-area view.

4. SPP monitors BES parameters that may have significant impacts upon its RC Areas and neighboring RC Areas as follows:

4.1. SPP maintains awareness of all Interchange Transactions that wheel-through, Source, or Sink in the SPP RC Areas.

4.1.1. SPP acts as a Scheduling Entity on behalf of the Market Operating Entities or PSEs in its Eastern Interconnection RC Area by approving all transactions that wheel-through, Source and Sink in its Eastern Interconnection RC Area. SPP makes available its Eastern Interconnection RC tag information to all RCs in the Eastern Interconnection as necessary.

4.1.2. SPP is not a scheduling entity in the Western Interconnection. The RC maintains awareness of scheduling impacts on constraints through the Enhanced Curtailment Calculator (ECC).

4.2. SPP evaluates and assesses additional Interchange Transactions that could violate SOLs and/or IROLs. SPP utilizes Interchange information, real-time data in the SPP EMS, and SPP's constraint monitoring tools to make an assessment of the impacts of additional transactions on constraint loading. SPP is authorized to utilize all resources, including load shedding, to address a potential or actual IROL exceedances. This authorization is reiterated to each SPP RC Operator in their job description and by a personal memorandum from SPP's Chief Operating Officer (COO).

4.3. SPP monitors operational data submitted by BAs within the SPP RC Areas to ensure that the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards (CPS) and Disturbance Control Standards (DCS). If necessary, SPP will instruct the BAs in the SPP RC Areas to arrange for assistance from neighboring BAs. SPP has the

authority to instruct the acquisition of generation capacity and, if that instruction is not satisfied, instruct the shedding of load in the deficient BA Areas.

4.4. SPP will identify the cause of potential or actual SOL or IROL exceedances. SPP shall initiate control actions or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. SPP will choose the most effective means of relieving the IROL exceedance within 30 minutes including instructing generation re-dispatch, facility switching, and load shedding. SPP is authorized to instruct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5. SPP will communicate start and end times for time error corrections to all BAs within its RC Area in both the Eastern and Western Interconnections.

4.6 SPP will review TOP submitted Geo-Magnetic Disturbance (GMD) plans and acknowledge, via email, of both receipt and review. SPP will ensure that all TOPs and BAs within its RC Areas are aware of GMD forecast information and will assist in the development of any required response plans. For GMD levels K8 or above, SPP RC will initiate a satellite phone call test to ensure satellite phone functionality has not been damaged during the event. SPP will communicate GMD forecast information to its BAs and TOPs via one or more of the following; R-Comm, email communication, ICCP, and/or phone communication.

While performing the role of the GMD monitor, for all K-7 or higher GMD warnings and alerts, SPP will participate in the Space Weather Prediction Center (SWPC) initiated phone communication with other Reliability Coordinators via the NERC Hotline and perform a roll call of RCs expected to participate. As the GMD monitor, SPP RC will contact RCs who did not participate in the SWPC call, provide details concerning the GMD notification and post a message to the Reliability Coordinator Information System and, for the Western Interconnection RCs, to R-COMM utilizing the blast message option outlining the GMD event information.

4.7. SPP will participate in NERC Hotline discussions, assist in the assessment of the reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. SPP will disseminate this information within its RC Areas as necessary.

4.8. SPP monitors system frequency and its BAs' performance, and if necessary, will instruct any rebalancing required for a BA to return to CPS and DCS compliance to ensure reliability. SPP receives at least one real-time frequency point via ICCP for each Balancing Authority Areas in the SPP RC Areas. At the instruction

of SPP, its BAs shall utilize all resources, including firm load shedding, to balance load and generation.

4.9. SPP coordinates with other RCs and neighboring BAs or TOPs, as needed, in the development and implementation of mitigation plans for potential or actual SOL, IROL, CPS or DCS exceedances. SPP coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time RTA and next day OPA timeframes. SPP participates in periodic conference calls with neighboring RCs as necessary.

4.10. SPP will assist the BAs in the SPP RC Areas in arranging for assistance from neighboring RCs or BAs by issuing reserve sharing contingency notifications (for the Eastern Interconnection SPP RSG Members) or EEAs as appropriate.

4.11. SPP identifies sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and will implement corrective actions with the appropriate BA. SPP receives the real-time ACE for each BA Area in the RC Areas via ICCP. The SPP RC receives an alarm if any ACE values change significantly or exceed a predefined limit. Excessive ACEs would be addressed by a call to the BA to determine the cause of the deviation and the course of action that the BA has planned and/or implemented to address the situation. Assistance would be provided in the Eastern Interconnection RC Areas by accessing operating reserves with the SPP Reserve Sharing Group to address the deviation should that be required. Should the situation be causing overloads on system facilities, instruction would be issued to dispatch/re-dispatch generation to relieve the situation.

4.12. SPP maintains awareness that Special Protection System (SPS) or Remedial Action Scheme (RAS) within the SPP RC Areas are armed. The host BA/TOP is required pursuant to applicable SPP RDS to keep SPP informed of the operational status of the SPS. If there is concern with the state of an SPS/RAS, and if not previously informed, the RC shall contact the responsible TOP, or neighboring entity as applicable, to inquire about the SPS/RAS state change.

5. SPP will alert all affected BAs and TOPs in its RC Areas, and all affected RCs within the Interconnection when it foresees an IROL exceedance or a significant loss of real and/or reactive generation capacity within its RC Areas through OPA and/or RTA. SPP will disseminate this information to its BAs and TOPs, utilizing appropriate communication channels, such as R-Comm, verbal communications, etc.

6. SPP confirms RTA and/or OPA results and determines the effects within its RC Areas and adjacent RC Areas. SPP will derive and discuss options to mitigate potential or actual SOL or IROL exceedances and identify and implement only those actions as necessary as to always act in the best interest of the Interconnection at all times.

Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

## F. Emergency Operations

1. In the event the loading of transmission facilities progresses to, or is projected to progress to, an SOL exceedance, SPP will use congestion management processes to reduce the loading to prevent an exceedance as soon as practicable. In the event the loading of transmission facilities progresses or is projected to progress to an IROL exceedance, SPP will take immediate actions, but no longer than 30 minutes, to return loading to the facility rating up to and including load shed.

2. SPP maintains copies of all pertinent operating guides/instructions as supplied by SPP RC Members and Reliability Customers. SPP reviews and coordinates these instructions with the BAs and TOPs in the SPP RC Areas. The SPP RC Operator maintains communication with the Transmission Operator who may be implementing these guides for local area relief to ensure regional reliability is not jeopardized by the implementation of said procedures. SPP RC Operators will instruct the appropriate Transmission Operators to take specific actions on how to mitigate the situation.

3. For the Eastern Interconnection RC Area, SPP will comply with the provisions of the NERC TLR procedure as follows. If the SPP RC is the sink RC and receives notification via the IDC that another RC has issued a TLR that calls for curtailment and/or halts of transactions sinking in SPP, the SPP RC will use the IDC to acknowledge the transaction curtailments and/or halts for the next hour, or current hour, and monitor the transactions to ensure that the transaction curtailments/halts are properly implemented. SPP acts as the sink RC in the IDC for transactions sinking into ERCOT across the East and North DC ties and for transactions sinking into Western Interconnection across the Eddy County, Stegall, Blackwater, Rapid City, Miles City, Lamar and Sidney HVDC ties.

    3.1. If SPP determines, through Source-to-Sink impact evaluation, that curtailment of a transaction as identified by the IDC would actually increase flows on the constraint for which relief has been requested, it will not acknowledge curtailment of such transaction. SPP may also determine that, through Source-to-Sink impact evaluation, transactions having a significant impact on the constraint exist but are not identified for curtailment by the IDC. In those cases, SPP will instruct curtailment of those transactions as necessary.

    3.2. If SPP receives notification from the IDC that SPP has a Generation to Load (GTL) relief obligation in response to a TLR issuance, SPP will utilize its market systems to calculate and send dispatch instructions to its Market Participants (MPs) necessary to achieve the relief.

3.3. SPP will follow procedures included in Market Protocols and its operating procedures to implement relief procedures, up to and including the point that emergency action is necessary. When SPP observes constraint loading that approaches the applicable SOL, it will communicate with the constraint owner to verify actual real-time flows and coordinate necessary actions to be taken. SPP will make a coordinated decision based on current and/or anticipated conditions to pursue relief by using the congestion management process.

4. For the Western Interconnection, SPP will utilize the Western Interconnection Congestion Management Methodology, including Unscheduled Flow Mitigation Procedure (UFMP).

5. SPP will monitor system frequency and its BAs' performance. If SPP determines that one or more of its BA areas are contributing to a frequency excursion, SPP will instruct the BA(s) to use all resources available, including load shedding, to comply with CPS and DCS requirements.

6. SPP will take or instruct whatever action is needed, including load shedding, to mitigate an energy emergency within the SPP RC Areas. SPP will provide assistance to other RCs experiencing an energy emergency as necessary.

7. SPP requires that any BA Area within its RC Areas that is experiencing an energy emergency, first use Operating Reserves available within its applicable Reserve Sharing Group (RSG). If the energy emergency still persists, SPP will issue an EEA on behalf of the deficient BA Area.

## G. System Restoration

1. SPP is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Areas and has a written copy of each plan in its possession. SPP verifies that the most current plans are on file on an annual basis. During system restoration, SPP monitors the restoration progress and coordinates any needed assistance.

2. SPP has regional restoration plans for the SPP RC Areas that provides coordination between individual restoration plans of each SPP Transmission Operator and that ensures reliability is maintained during system restoration events. The SPP RC Areas Regional Restoration Plans and NERC Reliability Standards require that the role of the SPP RC during system restoration is to facilitate this coordination. Furthermore, the SPP RC approves, communicates, and coordinates re-synchronization of system islands or synchronizing points such that a burden is not caused on adjacent TOP, BA, or RC Areas. SPP Communications Protocols delineate the processes for Emergency Communications.

3. SPP will disseminate information regarding restoration to neighboring RCs and BAs/ TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via phone call. SPP will also use the NERC Hotline for updates to other RCs as needed.

## H. Facility

SPP performs the RC function at each of its two Coordination Centers. Each Coordination Center has the necessary facilities for the SPP RCs to perform their responsibilities. Full functionality is provided with full backup of the systems, communications, data, and tools required for SPP to perform as the RC for its RC Members and Reliability Customers. Both primary and alternate sites are staffed and functional 24x7.

1. SPP has redundant data communications between the two SPP sites, which are staffed 24x7 with working communications such as voice and data links between RC Member and Reliability Customer sites and SPP systems. SPP also employs a Voice-over-IP (VOIP) phone system that allows the phones to ring at both Coordination Center sites simultaneously. Cell phones are used as the alternate voice communication capability.

   SPP IT's 24x7 desk and additional on-call staff provide support of the voice and data communications, hardware, and software, working with communication service companies as appropriate.

2. A satellite phone system is installed at both of SPP's Coordination Centers as well as at all SPP RC Areas BA/TOP primary operations centers, for purposes of communicating during emergency conditions per SPP Communications Protocols. This system bypasses the Public Switched Telephone Network (PSTN) and can be used for point-to-point or broadcast (all-call) communications. The satellite service can also route a phone call to a land line, providing access to any operable wire or wireless phone.

3. SPP has detailed real-time monitoring capability of the SPP RC Areas and sufficient monitoring capability of surrounding RC Areas to ensure that potential or actual SOL or IROL exceedances are identified. SPP has monitoring systems that provide information that can be easily understood and interpreted, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. SPP monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within the SPP RC Areas. SPP monitors both real and reactive power system flows,

operating reserves, and the status of system elements that are or could be critical to SOLs and IROLs and system restoration requirements within the SPP RC Areas.

4. SPP utilizes two separate EMS clusters, an Authorized cluster and an Unauthorized cluster. If the Primary Location is lost, the primary EMS systems in the Alternate Location will automatically take over EMS functionality at the Alternate Location. As part of the EMS model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

5. SPP utilizes two separate ICCP clusters, a primary cluster and a back-up cluster (secondary ICCP). If the Primary Location is lost, the primary ICCP systems located in the Alternate Location will automatically take over primary ICCP functionality. As part of the ICCP model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

6. Per the applicable SPP RDS, SPP RC Members and Reliability Customers are required to send and receive near real-time data to both the primary and secondary systems concurrently as appropriate. Data from both systems are fed to the EMS providing an alternate data source for use when the primary source is failed for any reason.

## I. Staffing

1. SPP 24x7 operations consists of four RC Operators and two Shift Engineers. The personnel is split between our primary and our alternate facilities with two RC Operators and one Shift Engineer at each location. These RC Operators and Shift Engineers are required to hold the NERC RC certification as well as being desk qualified at their position. SPP requires its RC Operators to complete yearly training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

2. SPP ensures that its RC Operators have a comprehensive understanding of the SPP RC Areas and required interaction with neighboring RCs. The SPP RC Operators have an extensive understanding of the RC Member and Reliability Customer systems within the SPP RC Areas such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. SPP makes year-round training opportunities available for the RC Operators, which includes the use of a Dispatcher Training Simulator (DTS) to provide realistic simulations of system emergencies described in the previous section.

   SPP creates training and performance support to ensure the SPP RC Operators understand the SPP region and the interface with neighboring regions. This includes opportunities for continuing education hours, including required

emergency operations and simulation hours. This training includes familiarization with Member BAs/TOPs by including RC training on the RC Members' and Reliability Customers' operating guides, system configuration, and transmission facilities. Control Center evacuation training and performance-based exercises are provided annually through instructor-led courses. Operations personnel who have a role in the evacuation plan are required to participate in the evacuation training and performance-based exercise annually. In addition, SPP conducts regional system restoration drills annually.

SPP's training department documents all training for recordkeeping and reporting purposes. All information required by the NERC Continuing Education program is available in a variety of report formats.

3. An Officer of SPP has signed the NERC Reliability Coordinator Standards of Conduct on behalf of the SPP RC. Each SPP RC Operator is required to sign and receive training on the SPP Standard of Conduct annually. The SPP Standard of Conduct requires the signatory to maintain proper confidentiality procedures and processes. SPP is an independent organization with an independent Board of Directors. SPP's independence enables its staff to fully comply with both the NERC and SPP Standards of Conduct.

## Appendix A – BAs and TOPs in SPP RC Areas

Balancing Authorities and Transmission Operators in the SPP Reliability Coordination Areas:

| Entity | BA | TOP | East | West |
|---|---|---|---|---|
| Arlington Valley Power Cooperative (AVBA) | X | | | X |
| American Electric Power – West (AEP) | | X | X | |
| Arizona Electric Power Cooperative/SW Transmission Coop (AEPC) | | X | | X |
| Black Hills Corporation (BHE) | | X | | X |
| City Utilities of Springfield (CUS) | | X | X | |
| Colorado Springs Utilities (CSU) | | X | | X |
| Corn Belt Power Cooperative (CBPB) | | X | X | |
| El Paso Electric (EPE) | X | X | | X |
| Empire District Electric Company/Liberty Utilities (EDE) | | X | X | |
| Farmington Electric Utility System (FEUS) | | X | | X |
| First Light Energy (BNBA) | X | | | X |
| Grand River Dam Authority (GRDA) | | X | X | |
| City of Independence Power & Light Department, Missouri (INDP) | | X | X | |
| Gridforce Energy Management (GRID) | X | | | X |
| CORE Electric Cooperative (CORE) | | X | | X |

| Entity | BA | TOP | East | West |
|---|---|---|---|---|
| ITC Great Plains (ITC) | | X | X | |
| The Board of Public Utilities, Kansas City, Kansas (BPU) | | X | X | |
| Kansas City Power and Light Company (KCPL) | | X | X | |
| KCP&L Greater Missouri Operations Company (UCU) | | X | X | |
| Lincoln Electric System (LES) | | X | X | |
| Midwest Energy, Inc. (MIDW) | | X | X | |
| Nebraska Public Power District (NPPD) | | X | X | |
| Oklahoma Gas and Electric (OKGE) | | X | X | |
| Omaha Public Power District (OPPD) | | X | X | |
| Platte River Power Authority (PRPA) | | X | | X |
| Public Service of Colorado (PSCO) | X | X | | X |
| Sunflower Electric Power Corporation (SEPC) | | X | X | |
| Southwest Power Pool (SPP) | X | | X | |
| Southwestern Power Administration (SPA) | X | X | X | |
| Southwestern Public Service Company (SPS) | | X | X | |
| Tri-State G & T (TSGT) * | | X | X | X |
| Tucson Electric Power (TEPC) | X | X | | X |
| Western Areas Power Administration (WACM) | X | X | | X |
| Western Areas Power Administration (WALC) | X | X | | X |
| *Western Areas Power Administration (WAUE) | | X | X | |
| Western Areas Power Administration (WAUW) | X | X | | X |
| Western Farmers Electric Cooperative (WFEC) | | X | X | |
| Westar Energy, Inc. (WRGS) | | X | X | |

**Eastern and Western Interconnections*

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit II: NERC, *Emergency Operations*

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# A. Introduction

**1. Title:** **Emergency Operations**

**2. Number:** **EOP-011-4**

**3. Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

**4. Applicability:**

**4.1. Functional Entities:**

**4.1.1** Balancing Authority

**4.1.2** Reliability Coordinator

**4.1.3** Transmission Operator

**4.1.4** Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

**4.1.5** UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

**4.1.6** Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

**5. Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

## B. Requirements and Measures

**R1.** Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

**1.1.** Roles and responsibilities for activating the Operating Plan(s);

**1.2.** Processes to prepare for and mitigate Emergencies including:

**1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

**1.2.2.** Cancellation or recall of Transmission and generation outages;

**1.2.3.** Transmission system reconfiguration;

**1.2.4.** Redispatch of generation request;

**1.2.5.** Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

**1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

**1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

**1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

**1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

**1.2.5.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

**1.2.6.** Provisions to determine reliability impacts of:

**1.2.6.1.** Cold weather conditions; and

**1.2.6.2.** Extreme weather conditions.

**M1.** Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

**R2.** Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

**2.1.** Roles and responsibilities for activating the Operating Plan(s);

**2.2.** Processes to prepare for and mitigate Emergencies including:

**2.2.1.** Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

**2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1;

**2.2.3.** Managing generating resources in its Balancing Authority Area to address:

**2.2.3.1.** Capability and availability;

**2.2.3.2.** Fuel supply and inventory concerns;

**2.2.3.3.** Fuel switching capabilities; and

**2.2.3.4.** Environmental constraints.

**2.2.4.** Public appeals for voluntary Load reductions;

**2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions;

**2.2.6.** Reduction of internal utility energy use;

**2.2.7.** Use of Interruptible Load, curtailable Load, and demand response;

**2.2.8.** Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

**2.2.9.** Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

**2.2.10.** Provisions to determine reliability impacts of:

**2.2.10.1.** Cold weather conditions; and

**2.2.10.2.** Extreme weather conditions.

**M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

**R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:

**3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

**3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

**3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

**M3.** The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

**R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

**M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

**R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

**M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

**R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

**M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

**R7.** Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**M7.** Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

**R8**. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

**8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

**8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

**8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

**8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

**8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

**8.1.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

**8.2.** Provisions to provide the Load shedding plan to the Transmission Operator for review.

**M8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

# C. Compliance

## 1. Compliance Monitoring Process

**1.1. Compliance Enforcement Authority:** "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

**1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

**1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

## Violation Severity Levels

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1** | N/A | The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it. | The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator. | The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area.<br>OR<br>The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it. |
| **R2** | N/A | The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it. | The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator. | The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area.<br>OR<br>The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it. |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R3** | N/A | N/A | The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days. | The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator. |
| **R4** | N/A | N/A | The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator. | The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator. |
| **R5** | N/A | N/A | The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification. | The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators. |
| **R6** | N/A | N/A | N/A | The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | Alert. |
| **R7** | N/A | The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late. | The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late. | The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding.<br>OR<br>The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | OR<br>more of those entities 60 days or more late. |
| **R8** | N/A | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8. | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8. | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8.<br>OR<br>The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8. |

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Associated Documents

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | November 13, 2014 | Adopted by the NERC Board of Trustees | Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2. |
| 1 | November 19, 2015 | FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818 | |
| 2 | June 11,2021 | Adopted by the NERC Board of Trustees | Revised under Project 2019-06 |
| 2 | August 24,2021 | FERC approved EOP-011-2. Docket Number RD21-5-000 | |
| 3 | October 26, 2022 | Adopted by the NERC Board of Trustees | Revised under Project 2021-07 |
| 3 | February 16, 2023 | FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094 | |
| 4 | October 23, 2023 | Adopted by the NERC Board of Trustees | Revised under Project 2021-07 |
| 4 | February 15, 2024 | FERC Order issued approving EOP-011-4. Docket No. RD24-1-000 | |

## Attachment 1-EOP-011-4
## Energy Emergency Alerts

**Introduction**

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

**A. General Responsibilities**

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

**B. EEA Levels**

**Introduction**

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

**2.1 Notifying other Balancing Authorities and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

**2.2 Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

**2.3 Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

**2.4 Evaluating and mitigating Transmission limitations**. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

**2.5 Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

**2.5.1 All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line.

**2.5.2 Demand-Side Management**. Activate Demand-Side Management within provisions of any applicable agreements.

**3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:**

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

**3.1 Continue actions from EEA 2**. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

**3.2 Declaration Period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

**3.3 Reevaluating and revising SOLs and IROLs.** The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

**3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

**3.4 Returning to pre-Emergency conditions.** Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

**3.4.1 Notification of other parties.** Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

**Alert 0 - Termination.** When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

**3.4.2 Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit JJ: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

**PROCEEDING NO. 20A-0528E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN**

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# DIRECT TESTIMONY AND ATTACHMENTS OF BRAD NEBERGALL ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

**December 1, 2020**

Colorado PUC E-Filings System

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## ATTACHMENTS

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| Attachment BN-1 | Responsible Energy Plan |
| PUBLIC Attachment BN-2 | 2020 Electric Resource Plan |
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| HIGHLY CONFIDENTIAL Attachment BN-2 | 2020 Electric Resource Plan |

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Table 1 Summary of Electric Resource Plan Scenarios

## GLOSSARY

| Term | Meaning |
|---|---|
| AQCC | Colorado Air Quality Control Commission |
| Basin | Basin Electric Power Cooperative |
| BoR | Bureau of Reclamation |
| CAISO | California Independent System Operator |
| CDPHE | Colorado Department of Public Health and Environment |
| CEP | Clean Energy Plan |
| $CO_2$ | Carbon Dioxide |
| DSM | Demand-Side Management |
| EE | Energy Efficiency |
| ERP | Electric Resource Plan |
| EV | Electric Vehicle |
| GHG | Greenhouse Gas |
| GW | Gigawatt |
| IOU | Investor-Owned Utility |
| IRP | Integrated Resource Plan |
| MW | Megawatt |
| PSCo | Public Service Company of Colorado |
| RAP | Resource Acquisition Period |
| RE Act | Rural Electrification Act |
| REP | Responsible Energy Plan |
| RES | Renewable Energy Standard |
| RFP | Request for Proposals |
| RPS | Renewable Portfolio Standard |
| Tri-State | Tri-State Generation and Transmission Association, Inc. |
| WAPA | Western Area Power Administration |
| WESC | Wholesale Electric Service Contract |

## I. INTRODUCTION AND QUALIFICATIONS

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Brad Nebergall. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

**Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Senior Vice President, Energy Management.

**Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?**

A: I am testifying on behalf of Tri-State.

**Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY PRIOR TO BECOMING AN EMPLOYEE OF TRI-STATE.**

I graduated from Iowa State University with a B.S. in Business Administration and a focus in finance. I also have an MBA from the University of Houston. After several years working in commercial banking, I joined an affiliate of InterNorth in 1986, which eventually merged with another company to become Enron Corp. I spent the next 20 years serving in various roles within Enron affiliates, including founding Enron's natural gas trading business in England, co-founding an initiative to capture opportunities within NOx and $SO_2$ emissions credits trading, and managing Enron's Midwest Region with responsibility for all power, natural gas and diesel sales to large regional energy consumers. After Enron declared bankruptcy in 2001, I was recruited post-bankruptcy to restructure the wind power

operations of Enron Renewable Energy Corporation. I was responsible for all commercial and operational activities for 28 producing wind farms. I held that position through 2006.

**Q: WHEN DID YOU BEGIN YOUR EMPLOYMENT WITH TRI-STATE?**

A: I became a Tri-State employee in 2007. In 2008, I was promoted to my current position of Senior Vice President, Energy Management.

**Q: WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT, ENERGY MANAGEMENT FOR TRI-STATE?**

A: I am responsible for Tri-State's activities related to marketing, energy trading, origination, risk management, resource dispatch, corporate development and resource planning. My responsibilities require that I have knowledge of Tri-State's operations, strategic initiatives, costs/expenses, and long-term commitments to Members, lenders and other third parties. In addition, my job requires that I study and track market and industry conditions, including market prices for Tri-State's purchased fuel, its capital expenses and the price at which wholesale electricity can be bought and sold on the spot market.

**Q: DO YOUR RESPONSIBILITIES INVOLVE PLANNING TRI-STATE'S FUTURE GENERATION NEEDS AND THE RESOURCES TRI-STATE WILL BUILD OR PURCHASE TO MEET THOSE NEEDS?**

A: Yes. Tri-State's resource planning function is a significant part of my responsibility.

## II. PURPOSE OF TESTIMONY

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A: Given that this is the first Electric Resource Plan ("ERP") that Tri-State is filing under new Commission Rule 3605, it may be helpful to provide some background on Tri-State and context for the Commission's and parties' consideration of Tri-State's 2020 ERP. In that regard, my testimony begins with an overview of Tri-State, including its organization, membership, and generation and transmission systems, and discusses how Tri-State is different from investor-owned utilities and how those differences are relevant to the Commission's evaluation of Tri-State's ERP.

The next section of my testimony discusses the evolution of the Commission's regulation of Tri-State's resource planning and some of the unique challenges associated with the current ERP cycle. Next, I discuss Tri-State's Responsible Energy Plan ("REP"), which describes Tri-State's vision for transitioning to a clean energy portfolio and grid, and the relationship between the REP and Tri-State's 2020 ERP. The next section of my testimony provides an overview of Tri-State's resource planning process and discusses some of the key considerations that factored into the development of Tri-State's 2020 ERP.

Finally, I will provide an overview of Tri-State's 2020 ERP, including the objectives of the ERP, the various scenarios and alternatives that were considered, and Tri-State's preferred plan for purposes of moving forward into Phase II of this ERP proceeding.

**Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON BEHALF OF TRI-STATE.**

A: Tri-State's witnesses are:

Ms. Lisa Tiffin, Senior Manager, Analytics & Forecasting. Ms. Tiffin will address various topics associated with the Phase I of the ERP, including Tri-State's load forecast, the assessment of existing resources, planning reserve margins, and the forecasted assessment of need for additional resources.

Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's testimony will address technical aspects of Tri-State's Phase I filing, including costs and benefits of the integration of intermittent renewable energy resources; studies commissioned and prepared by Tri-State to support the development of this filing; modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems; emissions and water usage and the social cost of carbon.

Mr. Andy Berger, Senior Manager, Environmental Policy. Mr. Berger will provide an overview of the environmental laws and policies influencing Tri-State's resource planning and will explain how compliance with state and federal environmental laws affects Tri-State's Electric Resource Plan ("ERP").

Mr. Christopher Pink, Vice President, Transmission Engineering. Mr. Pink will discuss transmission system capabilities, including injection capabilities, of Tri-State's transmission system, Tri-State's transmission planning process, and, finally, he will provide a discussion of Tri-State's transmission needs and planned projects. He will provide information as required by Commission Rule 3605(d) or identify where such information can be found in the ERP.

Ms. Susan Hunter, Senior Manager, Origination. Ms. Hunter's testimony will address Tri-State's plan for meeting the resource need, including the Phase II evaluation process and Tri-State's proposed RFP.

## III. OVERVIEW OF TRI-STATE

**Q: SINCE THIS IS THE FIRST TIME THE COMMISSION WILL EVALUATE AND ISSUE A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN, IT MAY BE HELPFUL TO PROVIDE SOME BACKGROUND ON TRI-STATE, ITS MEMBERSHIP, AND ITS MISSION. WHEN WAS TRI-STATE ESTABLISHED?**

A: Tri-State was established in 1952.

**Q: WHY WAS TRI-STATE ESTABLISHED?**

A: A full answer to that question requires a short history review. Congress passed the Rural Electrification Act ("RE Act") in 1936. At that time, 90 percent of rural America lacked electric power. Congress was concerned with the failure of then-existing electric utilities to extend service to rural communities and determined that the national interest would be served by subsidizing rural electrification. The RE Act allowed rural electric distribution cooperatives such as Tri-State's original Members to receive government-subsidized loans to facilitate the delivery of electricity to rural customers.

In late 1951, discussion began among rural electric cooperatives in Colorado, Nebraska, and Wyoming concerning the adequacy of power being supplied to them by the United States Bureau of Reclamation ("BoR"). These cooperatives

ultimately determined that the supply of federal power on which they had historically relied would not be sufficient to meet their growing needs. The cooperatives decided they should develop electric generating facilities that they would own to ensure adequate power supplies for the future. The cooperatives formed Tri-State in 1952 to fulfill that purpose – to ensure a sufficient and reliable power supply for its Utility Members – and Tri-State's Members continue to own and govern Tri-State to meet their collective needs. This is important because this original purpose and the underlying collective benefit for its Members has continued to guide Tri-State and its resource planning decisions for the last nearly 70 years.

**Q: WHAT IS TRI-STATE'S MISSION ON BEHALF OF ITS MEMBERSHIP?**

A: Tri-State's primary corporate mission is to provide its Utility Members a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles.

**Q: PLEASE DESCRIBE TRI-STATE'S MEMBERSHIP.**

A: Tri-State has 42 Class A Utility Members and three Non-Utility Members. Tri-State's Utility Members consist of rural electric distribution cooperatives and public power districts which, like Tri-State, operate on a not-for-profit basis. Tri-State's Utility Members include 11 distribution cooperatives located in New Mexico, 17 distribution cooperatives located in Colorado, eight distribution cooperatives located in Wyoming, and two distribution cooperatives and four public power districts located in Nebraska. In addition to providing retail electric service in the

four states in which they are located, certain of Tri-State's Utility Members also provide retail electric service that extends into multiple other states. Tri-State's three Non-Utility Members are all located in Colorado. Figure 1 below generally depicts Tri-State's Utility Members and their service territories.

**Figure 1. Tri-State's Utility Members and Their Service Territories**



Tri-State operates in interstate commerce and facilitates the generation and transmission of wholesale electricity across a four state, 200,000 square mile area. Tri-State's Utility Members, in turn, serve customers in 56 Colorado counties, 20 Nebraska counties, 28 New Mexico counties, and 14 counties in Wyoming.

All of Tri-State's Colorado Utility Members have voted to exempt themselves from regulation by the Commission, as permitted by the Colorado Public Utilities Law.

**Q: HOW IS TRI-STATE GOVERNED?**

A: As I have described, Tri-State is a multistate, regional, generation and transmission cooperative corporation that operates on a not-for-profit basis in interstate commerce providing wholesale electric power and transmission services to its Utility Members. To best serve the varying and unique needs of its Members, Tri-State is directly owned and governed by its Members through a Board of Directors.

Tri-State's Board of Directors is comprised of representatives from each of its Utility Members who are elected by the local boards of their respective cooperative or public power district. Tri-State's Board meets on a monthly basis to make decisions regarding the strategic and business affairs of the cooperative. All matters requiring a decision by the Board are decided by a majority vote of the Board members present and voting. Each Utility Member is entitled to one vote. The Members, acting through their representatives on the Board, are responsible for approving rates, major capital investments, long-term contractual commitments and, as relevant here, Tri-State's resource planning decisions.

Recognizing that Board decisions have a significant impact on all Members, the Board acts for the collective benefit of all Members and seeks to treat all Members equitably. This means that Tri-State's assets and system are planned and operated on the basis of mutual benefits and the sharing of costs and risks among all Members. Through its democratic control, Tri-State's Board works to ensure that corporate decisions balance the interests of all Members in all states.

**Q: HOW IS TRI-STATE DIFFERENT FROM COLORADO'S INVESTOR-OWNED ELECTRIC UTILITIES?**

A: I believe the primary differences are that Tri-State is owned by its Members rather than shareholders, does not seek to generate a profit for outside investors, and is a multistate wholesale electricity supplier that does not provide retail electric service.

**Q: WHY ARE THESE DIFFERENCES IMPORTANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN?**

A: In several ways. First, Tri-State is a wholesale electricity supplier – an aggregator of its Utility Members' loads. It is not a retail electric utility like Colorado's two investor-owned electric utilities. This is important because Tri-State does not have a direct relationship with end-use retail consumers; that relationship is the exclusive province of Tri-State's Utility Members. As a result, Tri-State is not in the same position as Colorado's retail electric IOUs when it comes to certain resource planning issues such as energy efficiency and demand side management.

Second, unlike Colorado's two retail electric IOUs, which are essentially single-state utilities serving only Colorado customers, Tri-State is a multistate utility serving Members in four states which, in turn, serve customers in multiple states. This difference is important for two reasons. Rather than having a system that is designed to serve the needs of only one state, Tri-State's system has for decades been designed, constructed and operated to serve its Members in multiple states and without regard to state boundaries. As a result, Tri-State's resource planning decisions in Colorado, as well as the Commission's decisions within the scope of its resource planning authority, will have an impact on system operations outside of Colorado and vice versa. Likewise, Tri-State's integrated system must take into consideration the legislative and regulatory requirements and public policy goals of all states in which it operates, not just in Colorado.[1] These state requirements and goals differ among the states yet, under the cooperative business model, the associated costs of compliance are shared by all Members in all states.

Finally, while Tri-State's Board and Members share the Commission's interest in ensuring a reliable and affordable power supply, Tri-State's not-for-profit business model means many of the issues related to utility profits and ownership of resources, which frequently arise in IOU ERP proceedings and lead into subsequent rate cases, are not present in Tri-State's ERP. And, like the wholesale power rates of Colorado's two electric IOUs, Tri-State's wholesale power rates are

[1] Tri-State also has resource planning obligations and submits an Integrated Resource Plan to the Western Area Power Administration.

regulated by the Federal Energy Regulatory Commission ("FERC").

These and other differences between Tri-State and the two Colorado electric IOUs require different considerations as the Commission evaluates Tri-State's 2020 ERP. These considerations are discussed throughout Tri-State's Electric Resource Plan and the testimony of Tri-State's witnesses.

**Q: YOU HAVE MENTIONED TRI-STATE'S INTERSTATE GENERATION AND TRANSMISSION SYSTEM SEVERAL TIMES. PLEASE PROVIDE A BRIEF OVERVIEW OF TRI-STATE'S SYSTEM.**

A: Tri-State's generating fleet includes: Craig Generating Station, Laramie River Station, Springerville Generating Station Unit 3, J.M. Shafer Generating Station, Rifle Generating Station, Limon Generating Station, Frank R. Knutson Generating Station, Pyramid Generating Station, and Burlington Generating Station.[2] Tri-State's resource mix also includes power provided by Basin Electric Power Cooperative ("Basin") and the Western Area Power Administration ("WAPA") under long-term power purchase agreements. Finally, Tri-State's resource mix includes power purchase agreements associated with the following existing renewable resources: Cimarron Solar, Kit Carson Windpower, Colorado Highlands Wind, Carousel Wind, San Isabel Solar, Alta Luna Solar, and Twin Buttes II Wind, as well as contracts with six small hydropower producers.

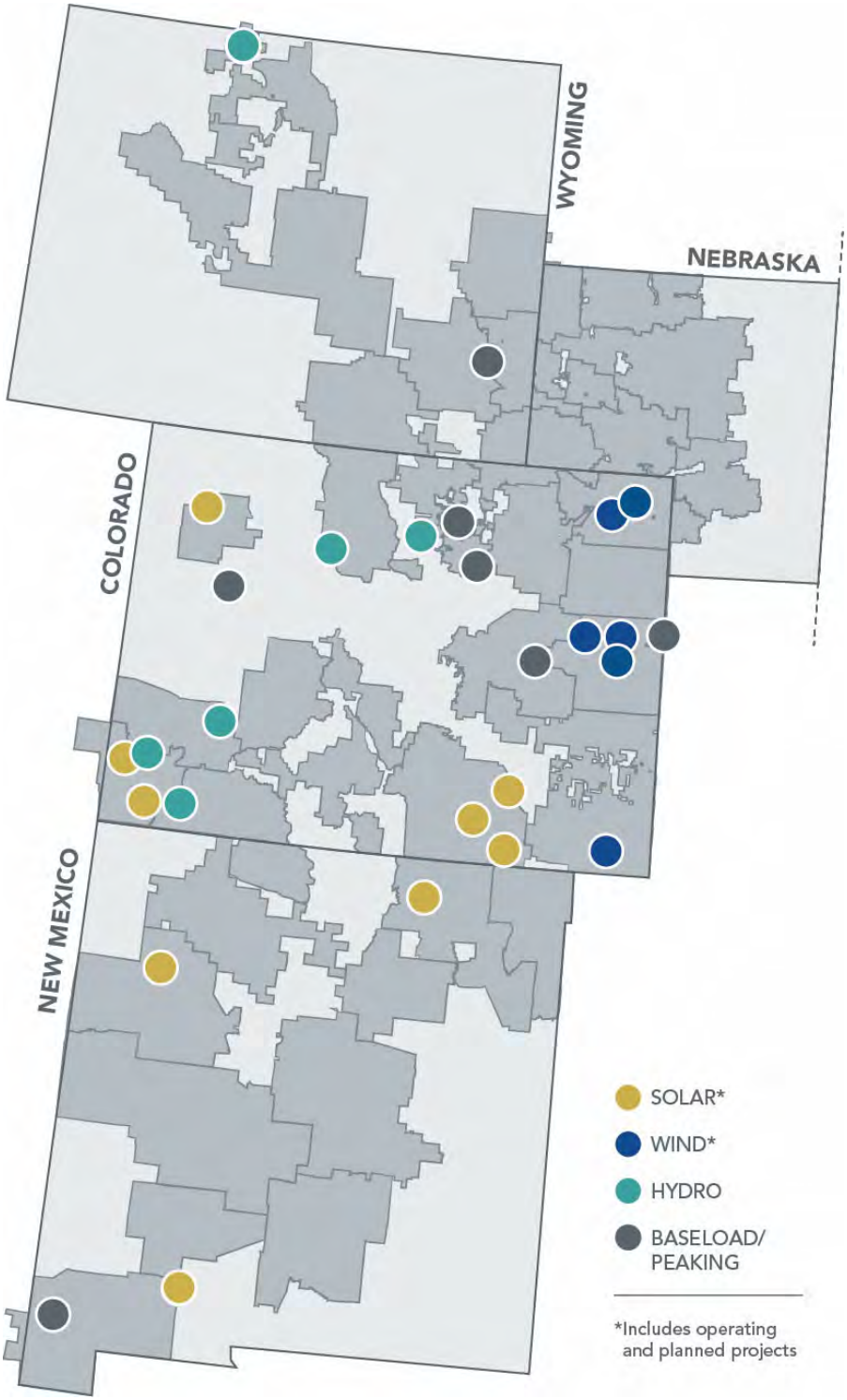
Tri-State's total system resource mix includes 2,432 MW of thermal generation

[2] Tri-State's Escalante Station, located in New Mexico, was retired on November 19, 2020, and is not included in this list.

resources, 452 MW of renewable wind and solar resources, 27 MW of small hydropower resources, and 580 MW of WAPA hydropower resources. Additionally, Tri-State Members own or contract for 131 MW of additional generation resources, consisting of renewable resources such as small solar, hydro, wind, landfill-gas and waste heat.

As a result of competitive bidding processes that Tri-State initiated in 2018 and 2019, Tri-State has executed contracts for additional wind and solar resources that are in various stages of development. Figure 2 below provides a general depiction of Tri-State's operating and planned generation resources. These resources are discussed in greater detail in Volume II of Tri-State's 2020 ERP.

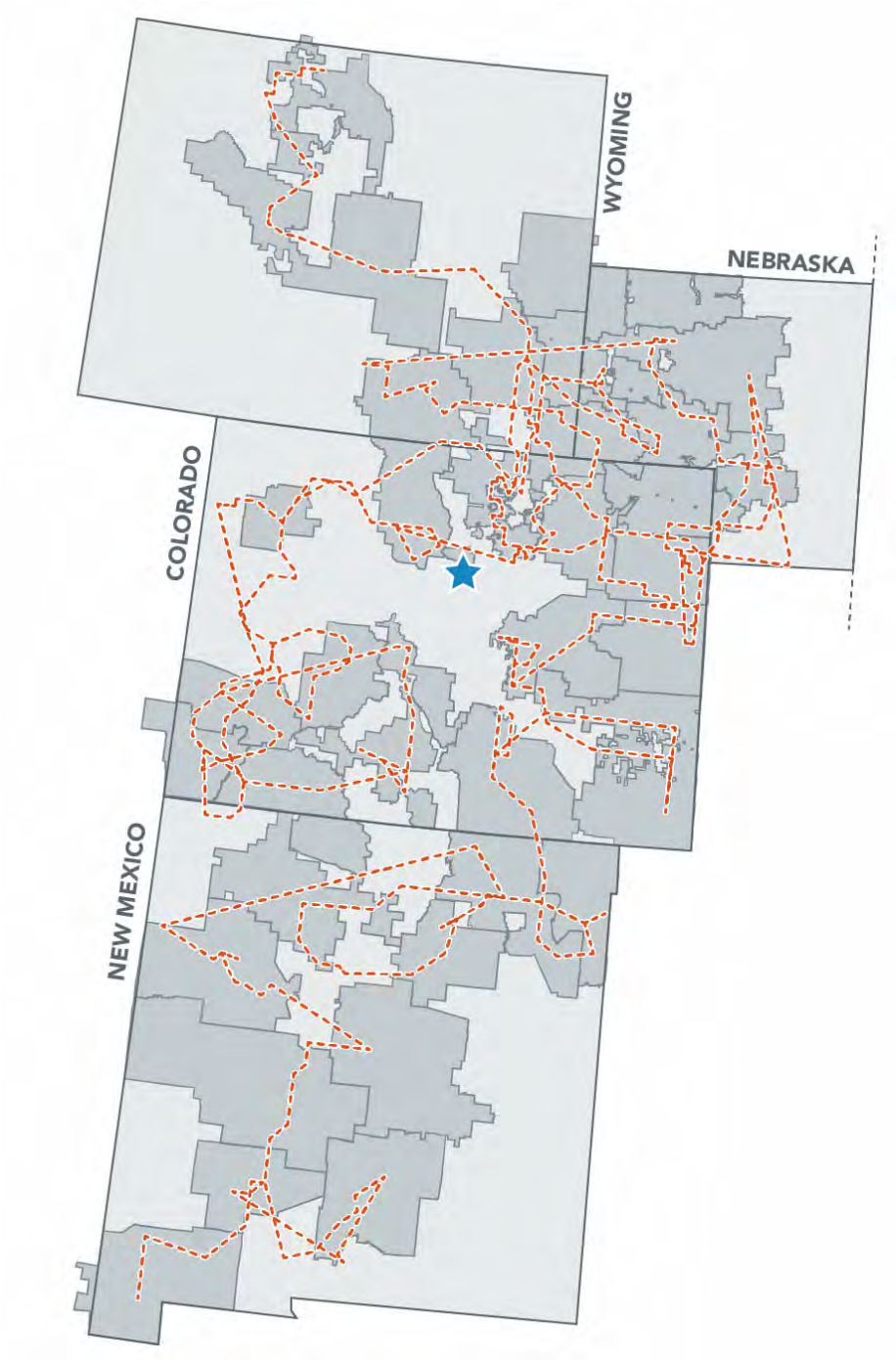
**Figure 2. Tri-State's Operating and Planned Generation Resources**



In 2019, Tri-State's Utility Member system peak demand was 3,009 MW and Utility Members purchased 16,413 GWh of energy from Tri-State. Tri-State's existing resources, resources under development, plans to retire certain of these resources, and Tri-State's projected resource mix in 2030 are discussed in greater detail in Ms. Tiffin's direct testimony.

Tri-State presently owns, operates, and maintains an extensive interstate transmission system with facilities located in four states: Colorado, New Mexico, Wyoming, and Nebraska. This transmission system includes over 5,665 miles of transmission lines with operating voltages up to 345 kV, 409 substations and switchyards, and over 475 communications sites used for system operations. In addition, Tri-State owns and operates the David A. Hamil DC Tie located in Stegall, Nebraska, which provides a means to transfer electric power between the Eastern and Western Interconnections. As of 2020, Tri-State's total transmission system investment is approximately $559,000,000. Tri-State also relies upon wheeling agreements with PSCo, WAPA, Public Service Company of New Mexico ("PNM"), PacifiCorp, and other transmission service providers for delivery of resources to its Utility Members. Figure 3 provides a general depiction of the location and extent of Tri-State's interstate transmission system.

**Figure 3. Overview of Tri-State's Transmission System**




Mr. Pink discusses Tri-State's transmission system and the information required by Commission Rule 3605(d) in greater detail in his testimony.

## IV. REGULATION OF TRI-STATE'S RESOURCE PLANNING

**Q: AT THE BEGINNING OF YOUR TESTIMONY, YOU NOTED THAT THIS IS THE FIRST TIME THE COMMISSION WILL BE EVALUATING AND ISSUING A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN. HOW HAS THE COMMISSION'S REGULATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN CHANGED OVER THE YEARS?**

A: During the nearly 70 years since Tri-State was established, the Commission has regulated Tri-State's resource planning to varying degrees. For the last 10 years, Commission Rule 3605 has required Tri-State to file its ERP as an informational report; however, during that period, the Commission did not conduct related adjudicatory proceedings and the Commission did not issue decisions approving Tri-State's ERP. This approach was the result of a proposal advanced by Tri-State and Western Resource Advocates in Docket No. 09I-041E and approved by the Commission in Decision No. C10-0101. Pursuant to that Decision, Tri-State filed its first ERP report on November 30, 2010, a subsequent full ERP report on October 30, 2015, and Annual Progress Reports in the intervening and subsequent years.

**Q: DID THAT INFORMATIONAL FILING REQUIREMENT SUBSEQUENTLY CHANGE?**

A: Yes. Pursuant to previous Commission Rule 3603, Tri-State's next full ERP would have been due on October 31, 2019. However, in 2019, the Colorado General Assembly passed Senate Bill 19-236, which became Colorado Revised Statute §

40-2-134. That statute required the Commission to promulgate rules requiring wholesale electric cooperatives to submit electric resource plans to the Commission for approval, and rules for the Commission's evaluation and approval of such ERPs. Given these new requirements and the timing of the associated rulemaking proceedings, Tri-State requested in Proceeding No. 19V-0311E a variance of the October 31, 2019, ERP filing deadline. The Commission granted that variance in Decision No. C19-0629 and held that the timing of Tri-State's next ERP filing would be established in the rulemaking proceeding required by § 40-2-134, C.R.S.

On July 31, 2019, the Commission issued its Notice of Proposed Rulemaking in Proceeding No. 19R-0408E regarding electric resource planning rules for wholesale electric cooperatives. The resulting new Rule 3605 went into effect nearly one year later on July 15, 2020, and established a December 1, 2020, filing deadline for Tri-State's full ERP. Commission Rule 3605 requires that Tri-State submit an electric resource plan that, in many respects, is substantially similar to those required of PSCo and Black Hills Energy. Rule 3605 also provides for Phase I and Phase II ERP processes for Tri-State.

Unique to this first ERP filing, Rule 3605 also required Tri-State to file the Assessment of Existing Resources section of its ERP into an adjudicated proceeding on June 1, 2020, for review by the Commission and interested parties. Finally, I would note that certain of the Commission's ERP rules that are at issue in Proceeding No. 19R-0096E apply to Tri-State; however, those rules have not

been finalized and, therefore, are not incorporated into Tri-State's 2020 ERP.

**Q: HOW IS THE CHANGE IN THE RESOURCE PLANNING RULES RELEVANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN?**

A: The change in resource planning rules applicable to Tri-State presents primarily practical challenges that Tri-State believes the Commission should consider as it evaluates this first ERP under the new rules.

First, the new rules presented timing challenges for Tri-State. While Tri-State was preparing to file its ERP in October 2019 under the prior resource planning rules applicable to Tri-State, those efforts were largely suspended when SB19-236 became law and Tri-State awaited the Commission's development of new resource planning rules for wholesale electric cooperatives. As noted previously, those new rules did not take effect until July 15, 2020 – only four-and-a-half months before Tri-State's first ERP under the rules was due to be filed. Tri-State had a general understanding of what those rules would be as a result of participation in the rulemaking proceeding; however, it could not proceed with certainty until the rules were finalized.

At the same time, Tri-State was required to prepare, file, and respond to numerous and extensive discovery requests related to its June 1, 2020, Assessment of Existing Resources (Proceeding No. 20M-0218E). The Rule 3605(c) information required in this advance filing ordinarily would not be filed separately and would be included in the full ERP itself, as is the case for similar information contained in the

ERPs filed by Public Service and Black Hills. However, in its Decision Adopting Rules, the Commission explained that such advance filing would "allow for Staff and other parties to Tri-State's initial 2020 ERP proceeding to conduct discovery and learn about Tri-State's generation fleet and the underlying financial requirements in the months leading to the later assessment of Tri-State's complete ERP filing." Given the limited nature of the Commission's historical involvement in Tri-State's resource planning, Tri-State recognizes the potential benefits of providing this information in advance of its initial ERP filing. Nevertheless, preparing that filing and responding to over 750 discovery requests presented a substantial challenge at the same time that the same Tri-State personnel were working on the scenario development, modeling, and analyses for the full ERP.

During the course of the Assessment of Existing Resources proceeding, several parties provided recommendations concerning the process for developing, or the contents of, Tri-State's ERP. As Tri-State explained in its response to initial comments filed in that proceeding, not all of those recommendations were appropriate, and it was impossible to accommodate certain of these recommendations in time for the 2020 ERP filing. Depending on the particular recommendation, further changes could be addressed in a subsequent rulemaking or incorporated into Tri-State's next ERP, which is scheduled to be filed on June 1, 2023.

When the Commission deliberated on whether to close the Assessment of Existing Resources proceeding, it discussed further expectations of what Tri-State should

include in its full ERP filing. The Commission's written decision, however, did not issue until the afternoon of November 25, 2020 – two business days before the ERP was due on December 1, 2020. Accordingly, Tri-State did not have the Commission's written decision so as to specifically inform it of these additional requirements or in time to address all of these requirements in the ERP filing. Tri-State will review these new requirements and will supplement its ERP filing, as appropriate, as soon as possible.

Tri-State encourages the Commission to use this first ERP under the new rules to determine what does and does not make sense for purposes of the Commission's review of Tri-State's 2020 ERP, and consider any potential additional or changed requirements in the context of the 2023 ERP.

## V. TRI-STATE'S RESPONSIBLE ENERGY PLAN

**Q: IN JANUARY 2020, TRI-STATE ANNOUNCED ITS RESPONSIBLE ENERGY PLAN. PLEASE PROVIDE AN OVERVIEW OF THAT PLAN.**

A: Earlier this year, Tri-State's Board of Directors described its vision for the future of the cooperative in the Responsible Energy Plan ("REP"). The Responsible Energy Plan is included as **Attachment BN-1** to my testimony and outlines Tri-State's commitments and goals to help make that vision a reality. The REP focuses on reducing Tri-State's greenhouse gas ("GHG") and carbon dioxide ("$CO_2$") emissions, increasing Tri-State's use of renewable and clean energy resources, increasing Utility Member flexibility with respect to their power supply options, extending the benefits of a clean grid to our Utility Members and their customers

through various beneficial electrification initiatives, supporting our employees and communities as Tri-State implements these transitions, and striving to meet Colorado's clean energy goals while maintaining or reducing Tri-State's wholesale rates to its Utility Members.

**Q: SINCE JANUARY, SOME QUESTIONS HAVE BEEN RAISED CONCERNING THE DECISIONS INCLUDED IN TRI-STATE'S REP AND THE COMMISSION'S RESOURCE PLANNING AUTHORITY OVER TRI-STATE. WHAT IS TRI-STATE'S POSITION RELATIVE TO THIS ISSUE?**

A: Following SB19-236 being signed into law last year, Tri-State recognizes that its electric resource plans are subject to review and approval by the Commission. The announcement of the REP does not intrude upon or interfere with the Commission's resource planning jurisdiction. Some actions related to the REP - such as the retirement of existing generation resources, the assessment of need for additional resources, and Tri-State's plans for acquiring those resources - will require Commission approval in this or subsequent proceedings, and Tri-State will apply for those approvals. Other REP actions, however, do not necessarily require Commission approval; these include changes to the wholesale contract structure between Tri-State and its Utility Members, support for Utility Members' electric vehicle programs and other beneficial electrification initiatives, and Tri-State's support for employees and communities impacted by the transition from fossil fueled generation.

**Q: LET'S DISCUSS THE REP COMPONENTS IN MORE DETAIL. PLEASE DESCRIBE HOW THE RESPONSIBLE ENERGY PLAN IS INTENDED TO REDUCE TRI-STATE'S GREENHOUSE GAS AND CARBON DIOXIDE EMISSIONS.**

A: The REP, as originally announced, called for actions that would result by 2030 in a reduction of 90%, relative to 2005 levels, in the $CO_2$ emissions from generation resources owned or operated by Tri-State in Colorado. These actions were part of an overall effort that would also result in in a reduction of 70% by 2030, in the $CO_2$ emissions associated with Tri-State's Colorado wholesale power sales, compared to the base year of 2005. The REP contemplated a combination of plant retirements, the addition of new clean energy resources, and other actions needed to achieve these reductions including the retirement of the three Craig Station units by 2030. Additionally, the REP committed Tri-State to cancel its participation in the Holcomb Station project. These REP actions in Colorado are paired with Tri-State's decision to retire the Escalante Station in New Mexico by the end of 2020, and Tri-State separately announced the early retirement of the Nucla Station in 2019.

**Q: DURING THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING, SOME COMMENTERS CLAIMED THAT TRI-STATE'S RESPONSIBLE ENERGY PLAN WOULD NOT ACHIEVE THE 70% REDUCTION IN CO2 EMISSIONS IN COLORADO BY 2030 THAT YOU JUST MENTIONED. WERE THOSE CLAIMS ACCURATE?**

A: No. I believe those commenters confused the base case projections in the Assessment of Existing Resources with the REP initiatives. The 34% $CO_2$ emissions reduction shown in the base case projections reflected a "business as usual" base case and did not include GHG and $CO_2$ emission restrictions. It was not intended to illustrate all of Tri-State's Responsible Energy Plan commitments or the emission reductions associated with it, nor did it include additional actions required to reach Colorado GHG emission targets. Tri-State has modeled many scenarios for its full ERP, including scenarios related to $CO_2$ emission reduction and costs as required by Rule 3605 and to meet the commitments of the Responsible Energy Plan. These scenarios and the associated emission reductions are discussed in the testimony of Ms. Tiffin.

**Q: HAS TRI-STATE SUBSEQUENTLY REVISED ITS EMISSION REDUCTION PLANS AS COMPARED TO WHAT WAS ORIGINALLY DESCRIBED IN THE RESPONSIBLE ENERGY PLAN?**

A: Yes. Tri-State's plans for emission reductions continue to evolve. The REP, as originally presented, called for a reduction of 70%, relative to 2005 levels, in the $CO_2$ emissions associated with Tri-State's Colorado wholesale power sales by 2030. The preferred plan included in Tri-State's 2020 ERP now calls for a reduction of 80%, relative to 2005 levels, in the $CO_2$ emissions associated with Tri-State's Colorado wholesale power sales by 2030. This is consistent with Colorado's overall GHG and $CO_2$ emission reduction goals and is consistent with what would be required if Tri-State had voluntarily submitted a Clean Energy Plan.

Tri-State's preferred plan is discussed in greater detail in Ms. Tiffin's direct testimony.

**Q: PLEASE DESCRIBE THE RESPONSIBLE ENERGY PLAN'S PROVISIONS RELATED TO INCREASING TRI-STATE'S USE OF RENEWABLE AND CLEAN ENERGY RESOURCES.**

A: The REP calls for Tri-State to add to its system one Gigawatt (1 GW) of new utility scale renewable energy projects by 2024. These new resources consist of six utility scale solar projects and two utility scale wind projects: Axial Basin Solar (145 MW; 2023), Coyote Gulch Solar (120 MW; 2023), Dolores Canyon Solar (110 MW; 2023), Escalante Solar (200 MW; 2023), Spanish Peaks Solar (100 MW; 2022), Spanish Peaks II Solar (40 MW; 2023), Crossing Trails Wind (104 MW; 2020), and Niyol Wind (200 MW; 2021).[3] (See Figure 2) These additions will bring Tri-State's total renewable resources to over 2 GW, and we forecast that by 2024 50% of the power consumed by Tri-State's Utility Members' customers will come from renewable resources.

**Q: IN THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING THAT PRECEDED THIS ERP, SOME PARTIES EXPRESSED CONCERNS REGARDING THE POWER PURCHASE AGREEMENTS ("PPAs") TRI-STATE ENTERED INTO IN CONNECTION WITH THESE NEW RESOURCES. PLEASE EXPLAIN TRI-STATE'S POSITION WITH REGARD TO THOSE PPAs.**

[3] Figures and dates represent each project's nameplate capacity and anticipated commercial operation date.

A: First, I would note that Tri-State provided detailed data on these PPAs as part of its Assessment of Existing Resources and throughout the discovery process in Proceeding No. 20M-0218E. Information on these resources also is included in the revised Assessment of Existing Resources in the 2020 ERP.

These eight resources were contracted through a competitive request for proposals ("RFP") process in 2018 and 2019 prior to the Commission's new ERP rules for Tri-State. Tri-State's competitive acquisition process assured that these new resources provide the best value for its Utility Members. Furthermore, the timing of this competitive acquisition process was intended to ensure that the projects, and by extension Tri-State and its Utility Members, could secure the maximum benefits under the Investment Tax Credit and Production Tax Credit.

These resources will play a significant role in Tri-State's transition to a cleaner portfolio and its ability to timely achieve its emission reduction objectives. These resources also contribute to achieving Colorado's overall legislative and policy goals related to clean energy and emission reductions. Revisiting, let alone reopening, these past renewable RFPs would be counterproductive to Colorado's policy goals and to the interests of Tri-State's Utility Members and their customers in Colorado and in other States. Tri-State believes that the present ERP process should focus on future resource acquisitions and the retirement of existing resources.

**Q: WHAT STEPS HAS TRI-STATE TAKEN UNDER THE RESPONSIBLE ENERGY PLAN TO INCREASE ITS UTILITY MEMBERS' FLEXIBILITY WITH REGARD TO POWER SUPPLY OPTIONS?**

A: For nearly 20 years, Tri-State's Utility Members have had the option to self-generate up to 5% of the energy they need to serve their member-customers. This option has been very popular and successful, with approximately half of Tri-State's Utility Members taking advantage of it, resulting in 130 MW of renewable energy projects in service or under development. Over the years, Tri-State has provided substantial financial subsidies in connection with such projects. Furthermore, some of Tri-State's Utility Members also have developed local renewable energy projects that exceed the 5% self-generation option pursuant to a Tri-State Board policy addressing such projects.

Given the growing interest in local clean energy, many of Tri-State's Utility Members have expressed a desire for more flexibility in their power supply options. In response, the Tri-State Board, as part of the REP and otherwise, has taken a number of steps to provide that flexibility.

In December 2019, the Tri-State Board approved a new community solar program developed and recommended by the Members' Contract Committee. Under that program, Utility Members have the option to build or contract for community solar projects up to established energy thresholds. Solar generation under the program would not be included in the 5% self-supply option in the Utility Members' Wholesale Electric Service Contract ("WESC") with Tri-State. If all Tri-State Utility

Members took advantage of this new program, it would yield 63 MW of new local community solar projects. This program is being considered by the Federal Energy Regulatory Commission ("FERC") in a pending proceeding.

In 2019, the same Contract Committee began considering possible changes to the WESC that would provide Utility Members even greater power supply flexibility in the form of a partial requirements contract. In October 2020, the Tri-State Board approved a flexible partial requirements contract option and its associated board policies. Under that option, Utility Members may express their intent to transition from their current full requirements contract to a partial requirements contract by participating in an "open season" that will begin in early 2021. This initial "open season" will allocate up to 300 MW to the Utility Members. This self-supply option is in addition to the 5% self-supply option already included in the WESC and the community solar option. The partial requirements contract option also is being considered by FERC in a pending proceeding.

**Q: HOW ARE THESE VARIOUS SELF-SUPPLY OPTIONS FACTORED INTO TRI-STATE'S 2020 ERP?**

A: While we know which of Tri-State's Utility Members already are taking advantage of the 5% self-supply option under the WESC, we don't yet know how many Utility Members will implement community solar projects or transition to partial requirements contracts and, if so, in what capacity amounts. This challenge and how it was considered in the 2020 ERP is discussed in the testimony of Ms. Tiffin.

**Q: YOU MENTIONED ONE OF THE RESPONSIBLE ENERGY PLAN'S OBJECTIVES IS TO EXTEND THE BENEFITS OF A CLEAN GRID TO TRI-STATE'S UTILITY MEMBERS AND THEIR CUSTOMERS. PLEASE EXPLAIN THAT AND THE STEPS TRI-STATE HAS TAKEN SO FAR.**

A: Tri-State recognizes that the transition to a cleaner grid and power supply brings opportunities to power homes and businesses with reduced emissions electricity and to more efficiently use that electricity. Tri-State is committed to making sure that its Utility Members, and the retail end-use customers they serve, are able to take advantage of these opportunities.

So far, Tri-State has committed $2 million to extend the electric vehicle ("EV") charging network across our Utility Members' service territories by allocating each Utility Member $45,000 to install EV charging stations. Access to these charging facilities will make EV charging more available in rural communities and will give rural consumers the option to choose an EV the next time they buy a vehicle. It also will substantially expand the regional and state EV charging networks for everyone to use thereby advancing one of the Governor's Roadmap goals. Tri-State also is working with its Utility Members to explore additional opportunities for energy efficiency and demand-side management programs that can lower energy bills and energy use. Tri-State's beneficial electrification, EE and DSM initiatives, and the role they play in Tri-State's 2020 ERP are discussed further in the testimony of Ms. Tiffin.

**Q: HOW IS TRI-STATE SUPPORTING ITS EMPLOYEES AND THE VARIOUS COLORADO COMMUNITIES THAT WILL BE AFFECTED BY THE REP AND THE SHIFT TOWARD CLEAN GENERATION RESOURCES?**

A: Tri-State recognizes that its transition to a cleaner energy portfolio will affect the many employees who have worked hard for decades to "keep the lights on" by ensuring the safe and reliable operation of Tri-State's coal-fired power plants, and also will affect the Tri-State and subsidiary employees who have ensured the fuel supply for those plants. Similarly, this transition will affect the communities in which those plants are located.

Tri-State is providing support to the communities impacted by plant closures. For Craig Station and the Colowyo Mine, Tri-State is providing retraining and transition support for employees. Tri-State is working with its employees and community members to identify economic development opportunities, retraining programs, and other strategies to ease the transition over time. For example, one of the new solar projects I mentioned will be located on Colowyo Mine property. Tri-State also is working with local, state, federal, and industry leaders to develop, provide financial support for, and implement retraining, educational, and economic development solutions in addition to those that Tri-State is implementing on its own. While this issue is not addressed in the Commission's ERP rules for Tri-State, it is an important issue to Tri-State, its employees, and the impacted communities.]

## VI. TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN

**Q: WHAT ARE THE OBJECTIVES OF TRI-STATE'S 2020 ERP?**

A: Consistent with the Commission's ERP Rules, Tri-State's 2020 ERP is intended to describe Tri-State's need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need. Tri-State's 2020 ERP also is intended to accomplish these regulatory objectives while complying with the legislative and public policy requirements and goals that I discussed previously, and advancing progress toward Tri-State's own goals set forth in the Responsible Energy Plan.

I also would note that the 2020 ERP, together with the complementary initiatives in the REP, is intended to respond to what Tri-State's Utility Members and their member-customers have been asking for – a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity. Tri-State believes that the preferred plan submitted as a part of the 2020 ERP meets these objectives.

**Q: PLEASE PROVIDE AN OVERVIEW OF THE ERP FILING.**

A: Tri-State's 2020 ERP consists of two volumes containing the ERP itself and 18 appendices. Tri-State's 2020 ERP is included as **Attachment BN-2** to my testimony.

The ERP begins with an Executive Summary and an Introduction and Background section that discusses the development and organization of the 2020 ERP, and provides an update on progress made since Tri-State's 2015 ERP informational

filing.

The next section of the ERP addresses the current resource planning "landscape" in terms of Tri-State's system energy mix, market dynamics, and other external factors, and presents much of the information required by Rule 3605(a)(IV). As discussed in this section, Tri-State's 2020 ERP uses a 20-year resource planning period from 2021 through 2040 and, as required by Rule 3605(a)(IV)(A), a 10-year resource acquisition period ("RAP") beginning in 2021 and extending to the end of 2030. Tri-State believes that the next 12 to 24 months will provide greater clarity with respect to the variables, challenges, and opportunities that I discussed previously, and Tri-State recommends a measured approach to acquiring new resources during the RAP. Furthermore, Tri-State believes that additional time may allow for the development of new non-emitting dispatchable resources that could be cost-competitive for future acquisition, and Tri-State's 2023 ERP will provide an opportunity in the relatively near future to further consider these options.

The next section of the ERP provides Tri-State's assessment of resource needs, including current load and resource balance, RES/RPS requirements, GHG/CO2 reductions and demand-side management and energy efficiency.

The next section of the ERP presents Tri-State's Alternative Resource Analysis. This section discusses the Base Case as well as the multiple alternative plans that Tri-State considered, including the social cost of carbon and other plans required by Commission rules. This section compares the various plans and presents Tri-State's preferred plan. The next section outlines Tri-State's action plan for the

RAP, including the competitive bidding process and the ERP Implementation Report Plan.

The last section of Volume I of the ERP identifies the relevant confidential and highly confidential information, as required by Rule 3605(a)(IV)(K).

The first section of Volume II of the ERP provides load forecasting as required by Rule 3605(b) followed by details on commodity pricing.

The next section of the ERP presents Tri-State's Assessment of Existing Resources, including some of the information identified in the Commission's November 25, 2020 written decision closing Proceeding No. 20M-0218E.

The next section of the ERP addresses Tri-State's transmission system and transmission planning, and presents the information required by Rule 3605(d).

The next section of the ERP discusses in detail the Phase I modeling including constraints, assumptions, and methodology.

The last section of the report includes detailed environmental data for all scenarios.

**Q: WHAT IS THE RESOURCE NEED IDENTIFIED IN THE ERP?**

A: Tri-State's analysis shows a need for new capacity to provide replacement capacity support for the retirement of the Craig 3 unit in 2029. Tri-State also identifies the preferred addition of renewable and energy storage resources prior to that time, which will serve to achieve GHG reductions in the relatively near-term.

**Q: PLEASE DESCRIBE THE ALTERNATIVES TRI-STATE CONSIDERED IN DEVELOPING THE 2020 ERP.**

A: In addition to the Base Case, Tri-State considered seven alternative plans: four different base load scenarios yielding an 80% Colorado $CO_2$ emissions reduction, relative to a 2005 baseline, by 2030; two different low load scenarios yielding 80% Colorado $CO_2$ emissions reductions, relative to a 2005 baseline, by 2030; and a scenario that applies the social cost of carbon to all thermal generation units. Table 1 below provides a summary of the alternatives Tri-State considered.

**Table 1. Summary of Electric Resource Plan Scenarios**

| **Scenario** | **Description** |
|---|---|
| Base Case | Business as usual case to be used as a reference to measure other scenarios against. |
| 80% CR V1 | An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes forced (i.e. not a cost-driven model selection) expansion plan low level demand-response and aggressive level energy efficiency resources in Colorado. |
| 80% CR V2 | An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes only existing demand-side management and energy efficiency. |
| 80% CR V3 | An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that is similar to 80% CR V2, but includes an additional wind |

| | |
|---|---|
| | resource to improve carbon dioxide reduction and enhance reliability. |
| 80% CR V4 | An 80% carbon-reduction by 2030 scenario that is similar to 80% CR V2, but includes an additional solar resource to improve carbon dioxide reduction and enhance reliability. |
| Low Load 80% CR V1 | An 80% carbon-reduction by 2030 scenario that allows for low-level demand-response and/or low- or aggressive-level energy efficiency resources and uses the low load forecast. |
| Low Load 80% CR V2 | An 80% carbon-reduction by 2030 scenario that includes only existing demand-side management and energy efficiency resources and uses the low load forecast. |
| Social Cost of Carbon | A Social Cost of Carbon scenario that uses the technical support document under Executive Order 12866—Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, to determine the social cost of carbon and it applies the appropriate cost to carbon-emitting resources. |

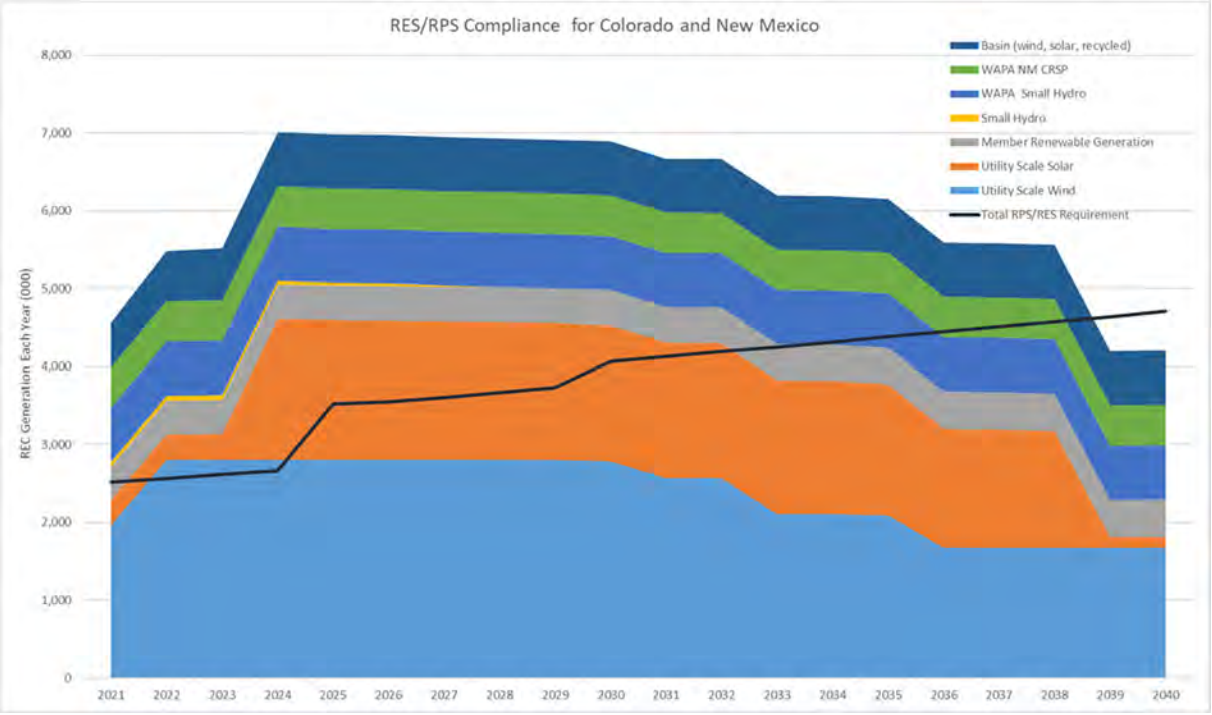
**Q: IS TRI-STATE PRESENTING A PREFERRED PLAN IN ITS 2020 ERP?**

A: Yes. Tri-State's preferred plan, which is forecast to result in an 80% $CO_2$ reduction as previously described, is detailed in Ms. Tiffin's testimony.

**Q: DOES THE PREFERRED PLAN ENABLE TRI-STATE TO COMPLY WITH ITS COLORADO RENEWABLE ENERGY STANDARD OBLIGATIONS AND SUPPORT ITS COLORADO UTILITY MEMBERS' OWN RENEWABLE ENERGY STANDARD AND RENEWABLE PORTFOLIO STANDARD OBLIGATIONS?**

A: Yes. Given that Tri-State operates an integrated generation and transmission system, the preferred plan will provide for compliance with Tri-State's and the Utility Members' RES and RPS obligations in Colorado and New Mexico. Figure 4 graphically depicts Tri-State's compliance with Colorado's RES and New Mexico's RPS.

**Figure 4. RES/RPS Compliance for Colorado and New Mexico**




RES and RPS compliance issues are discussed in greater detail in Ms. Tiffin's testimony.

**Q: ARE YOU FAMILIAR WITH THE RECENT HEARING AND DECISION BY THE COLORADO AIR QUALITY CONTROL COMMISSION IN CONNECTION WITH THE STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE?**

A: I did not participate in that hearing and am not directly responsible for issues related to Tri-State's compliance with the Regional Haze State Implementation Plan. I am, however, generally familiar with the Colorado Air Quality Control Commission's ("AQCC") actions at its recent hearing. Mr. Berger discusses the AQCC's actions in more detail in his testimony.

**Q: PLEASE DESCRIBE HOW THE RECENT ACTIONS BY THE AQCC MIGHT INFLUENCE TRI-STATE'S 2020 ERP.**

A: On Friday, November 20, 2020, the AQCC took action in a Regional Haze proceeding that would call for the retirement of Craig Unit 3 and several other coal-fired generating units in Colorado by December 31, 2028. The AQCC characterized its action as a "preliminary final action"; as such, the AQCC's decision is not final as of the date of Tri-State's ERP filing, and it is unclear at this time whether the AQCC's final decision will be the same as what was discussed at the recent hearing and, if so, when the final decision will be issued.

While Tri-State will continue to evaluate options related to the AQCC's action, if this action does, in fact, require the retirement of Craig Unit 3 by December 31, 2028, that retirement date would be inconsistent with certain analyses contained in this ERP filing. Specifically, the scenarios in this ERP (except for those requiring consideration of the social cost of carbon) provide for the retirement of Craig Unit

3 one year later, by December 31, 2029. Tri-State will address the AQCC's final decision, as appropriate, during Phase 1 of this ERP proceeding.

**Q: DOES TRI-STATE'S 2020 ERP FILING COMPLY WITH THE COMMISSION'S ERP RULES?**

A: Yes. Tri-State's 2020 ERP complies with all of the requirements of new Commission Rule 3605. A Compliance Table is included at page 4 in the ERP report.

**Q: WHAT APPROVAL IS TRI-STATE REQUESTING IN THIS PROCEEDING?**

A: Tri-State requests approval of its 2020 ERP, including Tri-State's assessment of need for additional resources during the current resource acquisition period, Tri-State's plans for acquiring such additional resources, and the proposed RFP to be used in conjunction with such resource acquisitions.

**Q: DOES THAT CONCLUDE YOUR TESTIMONY?**

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

**PROCEEDING NO. 20A-0528E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN**

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**VERIFICATION**

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STATE OF Colorado )
) ss:
COUNTY OF Adams )

I, Brad Nebergall, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Signed this 24th day of November, 2020, at Westminster, Colorado.

Subscribed and sworn to before me this 24th day of November, 2020.

Witness my hand and official seal.

Notary Public Faith Warner

My Commission expires: September 7, 2022

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES SEPTEMBER 7, 2022

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit KK: Division, *Operating Permit No. 96OPMF155* (July 1, 2021)

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# Colorado Department of Public Health and Environment

## OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

# AIR POLLUTION CONTROL DIVISION
# COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

**96OPMF155**

FACILITY ID: 081/0018

RENEWED: July 1, 2021
EXPIRATION DATE: July 1, 2026
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON
Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010
And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

FACILITY CONTACT PERSON
Name: Mike Tomasovic
Title: Environmental Supervisor
Phone: (970) 824-4411

**SUBMITTAL DEADLINES –**
Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Reports: Due February 1 & August 1
Annual Compliance Periods: January 1 – December 31
Annual Compliance Certification: Due February 1

**Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.**

**SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES**

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## SECTION I - General Activities and Summary

### 1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control $SO_2$ emissions; Unit 3 uses a lime spray-dryer scrubber to control $SO_2$ emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for $NO_x$ emissions. Units 1 and 2 also use overfire air and related $NO_x$ control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of $NO_x$ emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide ($SO_2$) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

## 2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

## 3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, $PM_{10}$, $PM_{2.5}$, $SO_2$, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

## 4. Accidental Release Prevention Program (112(r))

4.1 Based on the information provided by the Source, this facility is subject to the provisions of the Accidental Release Prevention Program in Section 112(r) of the Federal Clean Air Act (CAA).

## 5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), $SO_2$ (wet scrubber)

Unit 2: PM (baghouse), $NO_x$ (SCR), $SO_2$ (wet scrubber)

Unit 3: PM (baghouse), $NO_x$ (SNCR), $SO_2$ (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

## 6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

| Emission Unit | Facility ID | AIRS ID | Facility Stack ID | Description | Colorado Construction Permit | Pollution Control |
|---|---|---|---|---|---|---|
| Unit 1 Boiler | B001 | 001 | S001 | Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler<br>Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization | 10MF579 | Baghouse<br>Wet $SO_2$ scrubber<br>Low-$NO_x$ burners with overfire air |
| Unit 2 Boiler | B002 | 002 | S002 | Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler<br>Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization | | Baghouse<br>Wet $SO_2$ scrubber<br>Low-$NO_x$ burners with overfire air<br>SCR |
| Unit 3 Boiler | B003 | 003 | S003 | Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler<br>Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization | 12MF322-1 | Spray dryer<br>Baghouse<br>Low-$NO_x$ burners with overfire air<br>SNCR |
| Coal Handling – Units 1 & 2 | P101 | 004 | F101a | Coal hauling – Units 1 & 2 | 11MF276 | $MgCl_2$, water, or equivalent application, as necessary |
| | | | F101b | Coal unloading to grizzly – Units 1 & 2 | | Water spray with surfactant, as necessary |
| | | | F101c | Coal surge pile | | Water with surfactant, as necessary |
| | | | S101d | Primary coal crushing – Units 1 & 2 | | Baghouse |
| | | | S101e | Secondary coal crushing building – Units 1 & 2 | | Baghouse |
| | | | S101f | Common coal transfer building belt A | | Baghouse |
| | | | S101g | Common coal transfer building belt B | | Baghouse |
| | | | S101h | Coal stackout building – Units 1 & 2 | | Baghouse |
| | | | F101i | Coal stackout – Units 1 & 2 | | Telescopic chute |
| | | | F101j | Coal storage piles – Units 1 & 2 | | Water spray prior to stackout, as necessary |
| | | | S101k | Coal reclaim A – Units 1 & 2 | | Baghouse |

| Emission Unit | Facility ID | AIRS ID | Facility Stack ID | Description | Colorado Construction Permit | Pollution Control |
|---|---|---|---|---|---|---|
| | | | S101l | Coal reclaim B – Units 1 & 2 | | Baghouse |
| | | | S101m | Coal tripper deck & silos – Units 1 & 2 | | Baghouse |
| Ash Handling – Units 1 & 2 | P203 | 016 | S203a | Ash storage silo A – Units 1 & 2 | 11MF332 | Baghouse (Shared with S203e) |
| | | | S203b | Ash storage silo B – Units 1 & 2 | | Baghouse (Shared with S203d) |
| | | | F203c | Ash truck loading – Units 1 & 2 | | Low dust unloading system |
| | | | S203d | Silo B dry ash unloading – Units 1 & 2 | | Baghouse (Shared with S203b) |
| | | | S203e | Silo A dry ash unloading – Units 1 & 2 | | Baghouse (Shared with S203a) |
| Limestone Handling – Units 1 & 2 | P201 | 020 | F201a | Limestone hauling | 11MF415 | Paved portions of road |
| | | | S201b | Limestone truck unloading | | Baghouse |
| | | | S201c | Limestone silo #1 – Units 1 & 2 | | Baghouse |
| | | | S201d | Limestone silo #2 – Units 1 & 2 | | Baghouse |
| Coal Handling – Unit 3* | P102* | 023 | F102a | Coal train unloading – Unit 3 | 12MF322-2 | Water spray |
| | | | S102b | Coal conveyor portal building – Unit 3 | | Baghouse |
| | | | S102c | Coal conveyor portal building – Unit 3 | | Baghouse |
| | | | S102d | Secondary coal crushing (2 crushers) – Unit 3 | | Baghouse |
| | | | S102e | Coal stackout building – Unit 3 | | Baghouse |
| | | | F102f | Coal stackout – Unit 3 | | Telescopic chutes |
| | | | F102g | Coal storage pile – Unit 3 | | PM control plan, including compaction, chemical use or watering, as necessary |
| | | | S102h | Coal reclaim system – Unit 3 | | Baghouse |
| | | | S102i | Coal tripper deck & silos – Unit 3 | | Baghouse |
| | | | S102j | Loadout coal to railcars – Unit 3 | | Baghouse |
| | | | S102k | Common coal transfer building extension | | Baghouse |
| | | | F102l | Coal train loading | | None |
| Ash Handing – Unit 3 | P204 | 032 | S204a | Ash storage silo – Unit 3 | 12MF322-3 | Baghouse |
| | | | F204b | Ash truck loading (wet flyash and dry flyash) – Unit 3 | | Low dust loader (wet ash)<br>Baghouse (dry flyash) |

| Emission Unit | Facility ID | AIRS ID | Facility Stack ID | Description | Colorado Construction Permit | Pollution Control |
|---|---|---|---|---|---|---|
| | | | S204c | Recycle ash tank | | Baghouse |
| | | | F204d | Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3 | | $MgCl_2$ application on roads, as necessary |
| Lime Handling and Storage – Unit 3 | P202 | 035 | F202a | Lime hauling | 12MF322-4 | Paved portions of road |
| | | | S202b | Lime unloading | | Baghouse |
| | | | S202c | Lime conveying and silo | | Baghouse |
| | | | S202d | Lime day bin | | Baghouse |
| Cooling Towers – Units 1 & 2 | P401 | 040 | S401 | Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators | 96MF195 | Drift eliminators |
| | P402 | | S402 | Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators | | Drift eliminators |
| Unit 3 Cooling Tower | P403 | 044 | S403 | Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators | 98MF0141 | Drift eliminators |
| Emergency Diesel Fire-Pump Engine | N/A | N/A | N/A | Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower | N/A | None |
| Units 1&2 Emergency Diesel Generator | N/A | N/A | N/A | Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower | N/A | None |
| Unit 3 Emergency Diesel Generator | N/A | N/A | N/A | Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower | N/A | None |

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

**Table 1 - Craig Station Emission Unit Summary**

## SECTION II - Specific Permit Terms

### 1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Particulate Matter (PM) | 1.1 | 0.10 lb/MMBtu (NSPS Subpart D)<br><br>0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU) | Determined via Stack Testing | Baghouse O&M and Stack Testing | See Condition 1.1 |
| $SO_2$ | 1.2 | 1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D)<br><br>0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV)<br><br>0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU)<br><br>100% of flue gas treated (SIP)<br><br>0.160 lb/MMBtu 30-boiler operating day rolling average (SIP)<br><br>0.130 lb/MMBtu 90-boiler operating day rolling average (SIP)<br><br>90% reduction of $SO_2$ on 90-boiler operating day rolling average (SIP)<br><br>No more than 72 consecutive hours of operation without $SO_2$ control (SIP) | | CEMS<br><br>Coal Sampling Calculation Recordkeeping | Continuous<br><br>Daily |
| NOx | 1.3 | 0.7 lb/MMBtu 3-hour average (NSPS D)<br><br>0.30 lb/MMBtu calendar year average (SIP) | | CEMS | Continuous |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| | | 0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.)<br><br>4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10)<br><br>0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III) | | | |
| VOC & CO | 1.4 | | See Condition 1.4 | Recordkeeping and Calculation | Annually |
| Opacity | 1.5 | Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1)<br><br>Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP)<br><br>Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP)<br><br>Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP)<br><br>Not to exceed 20% during shutdown (SIP) | | COMS – May be verified by EPA Reference Method 9 | Continuous, 6-Minute Intervals |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Coal Requirements | 1.6 | Coal consumption records<br>Coal sampling | | Recordkeeping<br>ASTM Methods | Annually<br>Quarterly |
| CEMS | 1.7 | Monitor: Opacity, $NO_x$, $SO_2$, diluent gas, flow | | See Condition 1.7 | |
| NSPS D | 1.8 | See Condition 1.8 | | | |
| CO SIP | 1.9 | See Condition 1.9 | | | |
| Regional Haze | 1.10 | PM: 0.03 lb/MMBtu (See Condition 1.1)<br><br>$SO_2$: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2)<br><br>$NO_x$: 0.28 lb/MMBtu (Condition 1.3)<br><br>$NO_x$: 4,065 tpy (Condition 1.3) | | CEMS | Continuous |
| Acid Rain | 1.11 | See Section III of this Operating Permit | | Certification | Quarterly and annually |
| MACT UUUUU (MATS) | 1.12 | See Condition 1.12 and 5 | | | |
| CAM | 1.13 | See Condition 1.13 | | | |

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and $PM_{10}$ for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. $PM_{10}$ emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a $PM_{10}$ emission factor was developed using source testing.

1.2 **Sulfur dioxide ($SO_2$)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain $SO_2$ in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of $SO_2$ as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The $SO_2$ emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $SO_2$ emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the $SO_2$ regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average $SO_2$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the $SO_2$ emission limitations in this section (Condition 1.2.4) and emissions of $SO_2$ during any such period shall not be excluded from the determination of the Source's compliance with the $SO_2$ emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with $SO_2$ in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **$SO_2$ controls must achieve a ninety percent (90%) reduction of $SO_2$ on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential $SO_2$ emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily $SO_2$ emission rate, for each boiler operating day in an arithmetic average of the potential $SO_2$ emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the $SO_2$ rolling average basis that is referred to as $E_i$ in the equation below. Each day's potential $SO_2$ emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis $SO_2$ stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the $SO_2$ rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's $SO_2$ rolling average basis that is referred to as $E_0$ in the equation below. Each day's $SO_2$ stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent $SO_2$ reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an $SO_2$ control system achieving some reduction of $SO_2$ emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the $SO_2$ control equipment is operating normally.

1.2.5 Compliance calculations for $SO_2$ requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $SO_2$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

1.2.6 Annual emissions of $SO_2$ for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides ($NO_x$)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain $NO_x$, expressed as $NO_2$ in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The $NO_x$ emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with $NO_x$ in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of $NO_x$ during any such period shall not be excluded from the determination of the Source's compliance with the $NO_x$ emission limit. Compliance shall be determined on a unit-specific basis using data from $NO_x$ CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-$NO_x$ burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $NO_x$ emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the $NO_x$ regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average $NO_x$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual $NO_x$ limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for $NO_x$ requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $NO_x$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

1.3.6 Annual emissions of $NO_x$ for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

## 1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

## 1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

## 1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), $SO_2$, $NO_x$, (including diluent gas: either $CO_2$ or $O_2$), $CO_2$, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

*Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.*

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

## 1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

*Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.*

1.8.3 The Source shall determine compliance with the PM, $SO_2$, or $NO_x$ standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of $SO_2$ as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

## 1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, $SO_2$, $NO_x$ quarterly excess emission and monitoring report;

b. The required reports for $SO_2$ emissions (including emissions during all excluded periods as well as $SO_2$ content calculated from coal for each day, the $SO_2$ stack emissions for each day, and each day's $SO_2$ percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for $NO_x$ emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

## 1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **$NO_x$ emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **$NO_x$ limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual $NO_x$ limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

## 1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

## 1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

## 1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the $SO_2$ emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

## 2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Particulate Matter (PM) | 2.1 | 0.10 lb/MMBtu (NSPS Subpart D)<br><br>0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU) | Determined via Stack Testing | Baghouse O&M and Stack Testing | See Condition 2.1 |
| $SO_2$ | 2.2 | 1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D)<br><br>0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV)<br><br>0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU)<br><br>100% of flue gas treated (SIP)<br><br>0.160 lb/MMBtu 30-boiler operating day rolling average (SIP)<br><br>0.130 lb/MMBtu 90-boiler operating day rolling average (SIP)<br><br>90% reduction of $SO_2$ on 90-boiler operating day rolling average (SIP)<br><br>No more than 72 consecutive hours of operation without $SO_2$ control (SIP) | | CEMS<br><br>Coal Sampling<br>Calculation<br>Recordkeeping | Continuous<br><br>Daily |
| NOx | 2.3 | 0.7 lb/MMBtu 3-hour average (NSPS D)<br><br>0.30 lb/MMBtu calendar year average (SIP) | | CEMS | Continuous |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| | | 0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV)<br><br>0.46 lb/MMBtu (see Acid Rain requirements in Section III) | | | |
| VOC & CO | 2.4 | | See Condition 2.4 | Recordkeeping and Calculation | Annually |
| Opacity | 2.5 | Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1)<br><br>Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP)<br><br>Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP)<br><br>Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP)<br><br>Not to exceed 20% during shutdown (SIP) | | COMS – May be verified by EPA Reference Method 9 | Continuous, 6-Minute Intervals |
| Coal Requirements | 2.6 | Coal consumption records<br><br>Coal sampling | | Recordkeeping<br><br>ASTM Methods | Annually<br><br>Quarterly |
| CEMS | 2.7 | Monitor: Opacity, $NO_x$, $SO_2$, diluent gas, flow | | See Condition 2.7 | |
| NSPS D | 2.8 | See Condition 2.8 | | | |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| CO SIP | 2.9 | See Condition 2.9 | | | |
| Regional Haze | 2.10 | PM: 0.03 lb/MMBtu (See Condition 2.1)<br><br>$SO_2$: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2)<br><br>$NO_x$: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3) | | CEMS | Continuous |
| Acid Rain | 2.10.2 | See Section III of this Operating Permit | | Certification | Quarterly and annually |
| MACT UUUUU (MATS) | 2.12 | See Condition 2.12 and 5 | | | |
| CAM | 2.13 | See Condition 2.13 | | | |

**Table 3 – Unit 2 Emissions and Requirements Summary**

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and $PM_{10}$ for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. $PM_{10}$ emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a $PM_{10}$ emission factor was developed using source testing.

2.2 **Sulfur dioxide ($SO_2$)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain $SO_2$ in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of $SO_2$ as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The $SO_2$ emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $SO_2$ emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the $SO_2$ regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average $SO_2$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the $SO_2$ emission limitations in this section (Condition 2.2.4) and emissions of $SO_2$ during any such period shall not be excluded from the determination of the Source's compliance with the $SO_2$ emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with $SO_2$ in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **$SO_2$ controls must achieve a ninety percent (90%) reduction of $SO_2$ on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential $SO_2$ emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily $SO_2$ emission rate, for each boiler operating day in an arithmetic average of the potential $SO_2$ emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the $SO_2$ rolling average basis that is referred to as $E_i$ in the equation below. Each day's potential $SO_2$ emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis $SO_2$ stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the $SO_2$ rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's $SO_2$ rolling average basis that is referred to as $E_0$ in the equation below. Each day's $SO_2$ stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent $SO_2$ reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an $SO_2$ control system achieving some reduction of $SO_2$ emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the $SO_2$ control equipment is operating normally.

2.2.5 Compliance calculations for $SO_2$ requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $SO_2$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

2.2.6 Annual emissions of $SO_2$ for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides ($NO_x$)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain $NO_x$, expressed as $NO_2$ in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The $NO_x$ emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **$NO_x$ in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of $NO_x$ during any such period shall not be excluded from the determination of the Source's compliance with the $NO_x$ emission limit. Compliance shall be determined on a unit-specific basis using data from $NO_x$ CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-$NO_x$ burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $NO_x$ emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the $NO_x$ regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average $NO_x$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for $NO_x$ requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $NO_x$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

2.3.5 Annual emissions of $NO_x$ for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

## 2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

## 2.5 **Opacity**

### 2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

### 2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

### 2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

## 2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

## 2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), $SO_2$, $NO_x$, (including diluent gas: either $CO_2$ or $O_2$), $CO_2$, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

*Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.*

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

## 2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

*Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.*

2.8.2 The Source shall determine compliance with the PM, $SO_2$, or $NO_x$ standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30$^{th}$ day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of $SO_2$ as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

## 2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, $SO_2$, $NO_x$ quarterly excess emission and monitoring report;

b. The required reports for $SO_2$ emissions (including emissions during all excluded periods as well as $SO_2$ content calculated from coal for each day, the $SO_2$ stack emissions for each day, and each day's $SO_2$ percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for $NO_x$ emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

## 2.10 **Colorado Regulation No. 23, Regional Haze**

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30$^{th}$ day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

## 2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

## 2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

## 2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the $SO_2$ limitations in Condition 2.2, and the $NO_x$ limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

## 3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Particulate Matter (PM) | 3.1 | 443 tons/year, 12-month rolling total<br><br>0.03 lb/MMBtu (Filterable, MATS)<br><br>0.013 lb/MMBtu (Filterable, BACT and CO Reg 23)<br><br>0.018 lb/MMBtu (Filterable and condensable, BACT) | Stack Performance Testing | Baghouse O&M<br><br>Stack Performance Testing | Continuous<br><br>See Condition 3.1 |
| $PM_{10}$ | | 403 tons/year, 12-month rolling total<br><br>0.012 lb/MMBtu (Filterable, BACT and CO Reg 23)<br><br>0.018 lb/MMBtu (Filterable and condensable, BACT) | | | |
| $SO_2$ | 3.2 | 2,125 tons/year<br><br>0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT)<br><br>80% reduction of potential emissions, 30-day average (BACT)<br><br>1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less | CEMS | CEMS<br><br>Stack Performance Testing<br><br>Coal Sampling, Calculation, Recordkeeping | Continuous<br><br>See Condition 3.2<br><br>Daily |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| | | than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da)<br><br>0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1)<br><br>0.15 lb/MMBtu, 30-day rolling average (CO Reg 23)<br><br>0.20 lb/MMBtu, 30-day rolling average (MATS) | | | |
| NOx | 3.3 | 6,752 tons/year<br><br>0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT)<br><br>0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23) | CEMS | CEMS | Continuous |
| CO | 3.4 | 4,332 tons/year<br><br>1.25 lb/MMBtu, 8-hour rolling average (BACT) | CEMS | CEMS | Continuous |
| VOC | 3.5 | 58 tons/year | 0.003 lb/MMBtu, or AP-42, EPRI, stack test data | Recordkeeping and Calculation | Monthly |
| Lead (Pb) | | 0.054 tons/year | 2.82 lb/TBtu, or AP-42, EPRI, stack test data | | |
| Sulfuric Acid Mist (SAM) | | 0.10 tons/year | See Condition 3.5 | | |
| Fluorides | | 4.47 tons/year | 232.74 lb/TBtu, or AP-42, EPRI, stack test data | | |
| Opacity | 3.6 | Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) | | COMS – May be verified by EPA Reference Method 9 | Continuous |

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| | | During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)<br><br>Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1)<br><br>Not to exceed 20% (CO Reg 6 – State-only) | | | |
| Coal Requirements | 3.7 | 1,897,344 tons/year<br><br>Coal sampling | | Recordkeeping<br><br>ASTM Methods | Monthly<br><br>Quarterly |
| CEMS | 3.8 | Monitor: Opacity, $NO_x$, $SO_2$, CO, $CO_2$, diluent gas, flow | | See Condition 3.8 | |
| NSPS Da | 3.9 | See Condition 3.9 | | | |
| Regional Haze | 3.10 | See Condition 3.10 | | | |
| Acid Rain | 3.10.2 | See Section III of this Operating Permit | | Certification | Quarterly and Annually |
| MACT UUUUU (MATS) | 3.12 | See Conditions 3.12 and 5 | | | |
| CAM | 3.13 | See Condition 3.13 | | | |

**Table 4 – Unit 3 Emissions and Requirements Summary**

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns ($PM_{10}$)** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and $PM_{10}$. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb $PM_{10}$/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable $PM_{10}$ limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb $PM_{10}$/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons $PM_{10}$/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb $PM_{10}$/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and $PM_{10}$ emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and $PM_{10}$ emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide ($SO_2$)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for $SO_2$. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of $SO_2$**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for $SO_2$ are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for $SO_2$ for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for $SO_2$ is determined based on the average inlet and average outlet $SO_2$ emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of $SO_2$ per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain $SO_2$ emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This $SO_2$ emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable $SO_2$ emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for $SO_2$ and a new percent reduction for $SO_2$ are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for $SO_2$ emission limits is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable $SO_2$ percentage reduction requirements is determined based on the average inlet and outlet $SO_2$ emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the $SO_2$ emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring $SO_2$ emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the $SO_2$ control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, $SO_2$ emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential $SO_2$ emissions in place of a continuous $SO_2$ emission monitor at the inlet to the $SO_2$ control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an $SO_2$ CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A $CO_2$ or $O_2$ (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an $SO_2$ emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, $SO_2$ concentration data and $CO_2$ (or $O_2$) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable $SO_2$ and $CO_2$ (or $O_2$) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The $SO_2$ and, if required, $CO_2$ (or $O_2$) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the $SO_2$ data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the $O_2$ or $CO_2$ content of the flue cases at each location where $SO_2$ emissions are

monitored. For affected facilities subject to a lb/MMBtu $SO_2$ emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a $CO_2$ or $O_2$ monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 $SO_2$ concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the $SO_2$ emission rate in lb/MMBtu. $SO_2$ data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for $SO_2$. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the $SO_2$ standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb $SO_2$/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $SO_2$ emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the $SO_2$ regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average $SO_2$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for $SO_2$ requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $SO_2$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr $SO_2$ emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass $SO_2$ emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 $SO_2$ ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting $SO_2$ lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a $SO_2$ lbs value. Hourly $SO_2$ mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly $SO_2$ emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides ($NO_x$)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for $NO_x$. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This $NO_x$ emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the $NO_x$ emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for $NO_x$ emission limits is determined by calculating the arithmetic average of all hourly emission rates for $NO_x$ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

3.3.2 **6,752 tons of $NO_x$ per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This $NO_x$ emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable $NO_x$ emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for $NO_x$ is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for $NO_x$ emission limits is determined by calculating the arithmetic average of all hourly emission rates for $NO_x$ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the $NO_x$ emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring $NO_x$ emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a $NO_x$ emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the $O_2$ or $CO_2$ content of the flue cases at each location where $NO_x$ emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for $NO_x$. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the $NO_x$ standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of $NO_x$ (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of $NO_x$ and $CO_2$ or $O_2$ (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure $SO_2$, $NO_x$, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the $NO_x$ emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the $NO_x$ regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average $NO_x$ concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for $NO_x$ requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average $NO_x$ concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr $NO_x$ emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass $NO_x$ emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 $NO_x$ lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % $CO_2$ measurements, as applicable). The hourly $NO_x$ lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting $NO_x$ lb/hr value is then multiplied by the unit operating time for that hour to produce a $NO_x$ lbs value. Hourly

$NO_x$ mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly $NO_x$ emissions (in tons).

## 3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent $CO_2$ diluent cap when $CO_2$ measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

## 3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

## 3.6 **Opacity**

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

## 3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

## 3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), $SO_2$, $NO_x$, (including diluent gas: either $CO_2$ or $O_2$), CO, $CO_2$, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

*Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.*

## 3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for $SO_2$ and/or $NO_x$ and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

*Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.*

3.9.2.1 For $SO_2$, $NO_x$, PM, and $NO_x$ plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For $SO_2$ and $NO_x$ the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, $SO_2$, or $NO_x$ emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

## 3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

## 3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

## 3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

## 3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and $PM_{10}$ limitations in Condition 3.1, the $SO_2$ limitations in Condition 3.2, and the $NO_x$ limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

**4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil**

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

## 5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use $SO_2$ as a surrogate for HCl emissions and use an $SO_2$ CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

### 5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

| Table 2.1 Requirements | Pollutant | Emission limits and work practice standards | Specific requirements for test methods in Table 5 of Subpart UUUUU |
|---|---|---|---|
| a. | Filterable PM | 0.03 lb/MMBtu OR 0.3 lb/MWh (gross output) | Collect minimum of 1 dscm per run. |
| b. | Sulfur dioxide ($SO_2$)[1] | 0.2 lb/MMBtu OR 1.5 lb/MWh | $SO_2$ CEMS |
| c. | Mercury (Hg) | 1.2 lb/TBtu OR 0.013 lb/GWh | LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only. |

**Table 5 - Subpart UUUUU Table 2 Requirements**

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a $SO_2$ CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable $SO_2$ emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an $SO_2$ CEMS to monitor compliance with the alternate equivalent $SO_2$ emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

## 5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, $SO_2$, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, $SO_2$, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, $SO_2$, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

$Rmm_j$ = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

$Ter_k$ = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

$Rmt_k$ = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

$Smm_j$ = Maximum steam generation, $lb_{steam}$/h or lb/gross output, for EGU j,

$Cfm_j$ = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/$lb_{steam}$ or MWh/$lb_{steam}$) from EGU j,

$Smt_k$ = Maximum steam generation, $lb_{steam}$/h or lb/gross output, for EGU k, and

$Cfm_k$ = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/$lb_{steam}$ or MWh/$lb_{steam}$) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

$Her_i$ = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

$Rm_i$ = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

$Ter_i$ = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

$Rt_i$ = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

$Sm_i$ = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

$Cfm_i$ = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

$St_i$ = Steam generation in units of pounds from unit i that uses emissions testing, and

$Cft_i$ = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

$Her_i$ = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

$Rm_i$ = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

$Her_I$ = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

$Sm_i$ = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

$Cfm_i$ = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, $SO_2$, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, $SO_2$, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, $SO_2$, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30$^{th}$ (or, if applicable, 90$^{th}$ for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen ($O_2$) or carbon dioxide ($CO_2$) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the $O_2$ or $CO_2$ concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA $O_2$ or $CO_2$ data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an $SO_2$ CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the $SO_2$ CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the $SO_2$ CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average $SO_2$ emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly $SO_2$ emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA $SO_2$ concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 $O_2$ data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly $SO_2$ emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the $SO_2$ emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

## 5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

## 5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure $SO_2$, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, $CO_2$, $O_2$, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: $Her_i$ is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: $Hpv_i$ is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

## 5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

## 5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

## 5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or $SO_2$ monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each $SO_2$ or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or $SO_2$, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

## 5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

## 6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| F101a | Coal hauling – Units 1 & 2 | $MgCl_2$ or equivalent application |
| F101b | Coal unloading to grizzly – Units 1 & 2 | Water spray with surfactant |
| F101c | Coal surge pile | Water with surfactant, as necessary |
| S101d | Primary coal crushing – Units 1 & 2 | Baghouse |
| S101e | Secondary coal crushing building – Units 1 & 2 | Baghouse |
| S101f | Common coal transfer building belt A | Baghouse |
| S101g | Common coal transfer building belt B | Baghouse |
| S101h | Coal stackout building – Units 1 & 2 | Baghouse |
| F101i | Coal stackout – Units 1 & 2 | Telescopic chute |
| F101j | Coal storage piles – Units 1 & 2 | Water spray prior to stackout, as necessary |
| S101k | Coal reclaim A – Units 1 & 2 | Baghouse |
| S101l | Coal reclaim B – Units 1 & 2 | Baghouse |
| S101m | Coal tripper deck & silos – Units 1 & 2 | Baghouse |

**Table 6 - P101 Emission Units Description**

| Parameter | Permit Condition Number | Limitation | | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|---|
| | | | | | Method | Interval |
| Coal Consumption | 6.1 | 3,900,000 tons/year (through each P101 unit) | | | Recordkeeping | Annually |
| PM & $PM_{10}$ | 6.2 | F101a | | AP-42, 13.4.2 | Recordkeeping and Calculation | Annually |
| | | F101b<br>S101f<br>S101g<br>S101h<br>F101i<br>S101k<br>S101l<br>S101m | | PM: $2.22 \times 10^{-4}$ lb/ton<br>$PM_{10}$: $1.05 \times 10^{-4}$ lb/ton | | |
| | | S101d | | PM: 0.02 lb/ton<br>$PM_{10}$: 0.009 lb/ton | | |
| | | S101e | | PM: 0.05 lb/ton<br>$PM_{10}$: 0.02 lb/ton | | |
| | | F101c<br>F101j | | | | |
| Opacity | 6.3 | Not to exceed 20% opacity except during certain operational activities at | | | EPA Reference Method 9 | Semiannually See Condition 15 |

| | | | | | |
|---|---|---|---|---|---|
| | | which time not to exceed 30% opacity | | | |
| Fugitive Emissions | 6.4 | See Condition 6.4 | | | |
| Equipment Operation | 6.5 | See Condition 6.5 | | | |
| NSPS Y | 6.6 | Opacity not to exceed 20% | | See Condition 6.6 | |

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and $PM_{10}$ emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

## 7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| F102a | Coal train unloading – Unit 3 | Water spray |
| S102b | Coal conveyor portal building – Unit 3 | Baghouse |
| S102c | Coal conveyor portal building – Unit 3 | Baghouse |
| S102d | Secondary coal crushing (2 crushers) – Unit 3 | Baghouse |
| S102e | Coal stackout building – Unit 3 | Baghouse |
| F102f | Coal stackout – Unit 3 | Telescopic chutes |
| F102g | Coal storage pile – Unit 3 | PM control plan, including compaction, chemical use or watering, as necessary |
| S102h | Coal reclaim system – Unit 3 | Baghouse |
| S102i | Coal tripper deck & silos – Unit 3 | Baghouse |
| S102j | Loadout coal to railcars – Unit 3 | Baghouse |
| S102k | Common coal transfer building extension | Baghouse |
| F102l | Coal train loading | N/A |

**Table 8 - P102 Emission Units Description**

| Parameter | Permit Condition Number | Limitation | | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|---|
| | | | | | Method | Interval |
| Coal Consumption | 7.1 | 4,500,000 tons/year (each unit but tripper deck)<br><br>1,897,344 tons/year (tripper deck)<br><br>Coal Storage Pile: ≤ 14.5 acres | | | Recordkeeping | Monthly |
| PM & $PM_{10}$ | 7.2 | F102a<br>S102b<br>S102c<br>S102e<br>F102f<br>S102h<br>S102k<br>S102i<br>S102j | PM: 1.7 tons/year (all units combined)<br><br>$PM_{10}$: 0.7 tons/year (all units combined) | PM: $2.22 \times 10^{-4}$ lb/ton<br>$PM_{10}$: $1.05 \times 10^{-4}$ lb/ton | Recordkeeping and Calculation | Monthly |
| | | S102d | | PM: 0.05 lb/ton<br>$PM_{10}$: 0.02 lb/ton | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | F102g<br>F102l | | | | |
| Opacity | 7.3 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | | EPA Reference Method 9 | Semiannually See Condition 15 |
| Fugitive Emissions | 7.4 | See Condition 6.4 | | | | |
| Required Controls | 7.5 | See Condition 7.5 | | | | |
| NSPS Y | 7.6 | Opacity not to exceed 20% | | | See Condition 7.6 | |
| CAM | 7.7 | Condition 7.7 | | | | |

**Table 9 - P102 Emissions and Requirements Summary**

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

**Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)**

**Coal throughput through the tripper deck must not exceed 1,897,344 tons per year**

**Coal storage pile must not exceed 14.5 acres in size**

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, $PM_{10}$ emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and $PM_{10}$ and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

## 8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| F201a | Limestone hauling | Paved portions of road |
| S201b | Limestone truck unloading | Baghouse |
| S201c | Limestone silo #1 – Units 1 & 2 | Baghouse |
| S201d | Limestone silo #2 – Units 1 & 2 | Baghouse |
| N/A | Limestone conveying | Building enclosure |

**Table 10 – P201 Emission Units Description**

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Limestone Delivery | 8.1 | | | Recordkeeping | Annually |
| PM & $PM_{10}$ | 8.2 | F201a | PM: Paved: 3.97<br>Unpaved: 10.3<br>$PM_{10}$: Paved: 0.79<br>Unpaved: 2.9<br>EF in lb per vehicle mile traveled | Recordkeeping and Calculation | Annual |
| | | S201b<br>S201c<br>S201d | PM: 0.012 lb/ton<br>$PM_{10}$: 0.006 lb/ton | | |
| Opacity | 8.3 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | EPA Reference Method 9<br>Bagfilter O&M | Semiannually<br>Ongoing O&M |
| Baghouse | 8.4 | See Condition 8.4 | | | |
| Equipment Operation | 8.5 | See Condition 8.5 | | | |
| NSPS OOO (conveying only) | 8.6 | Opacity not to exceed 7% | | | |

**Table 11 – P201 Emissions and Requirements Summary**

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

## 9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| F202a | Lime hauling | Paved portions of road |
| S202b | Lime unloading | Baghouse |
| S202c | Lime conveying and silo | Baghouse |
| S202d | Lime day bin | Baghouse |

Table 12 – P202 Emission Units Description

| Parameter | Permit Condition Number | Limitation | | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|---|
| | | | | | Method | Interval |
| Lime Delivery | 9.1 | 28,000 tons/year via truck<br>28,000 tons/year via rail | | | Recordkeeping | Monthly |
| PM & $PM_{10}$ | 9.2 | F202a | PM: 14.9 tons/year, 12-month rolling total (all units combined)<br>$PM_{10}$: 2.9 tons/year, 12-month rolling total (all units combined) | PM: Paved: 5.39<br>Unpaved: 11.84<br>$PM_{10}$: Paved: 1.08<br>Unpaved: 3.37<br>EF in lb per vehicle mile traveled | Recordkeeping and Calculation | Monthly |
| | | S202b<br>S202c<br>S202d | | PM: 0.012 lb/ton<br>$PM_{10}$: 0.006 lb/ton | | |
| Opacity | 9.3 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | | EPA Reference Method 9<br>Bagfilter O&M | Semiannually<br>Ongoing O&M |
| 12MF322-4 Baghouses | 9.4 | See Condition 9.4 | | | | |
| Equipment Operation | 9.4.3 | See Condition 9.4.3 | | | | |

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and $PM_{10}$ emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

## 10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| S203a | Ash storage silo A – Units 1 & 2 | Baghouse (Shared with S203e) |
| S203b | Ash storage silo B – Units 1 & 2 | Baghouse (Shared with S203d) |
| F203c | Ash truck loading – Units 1 & 2 | Low dust unloader |
| S203d | Silo B dry ash unloading – Units 1 & 2 | Baghouse (Shared with S203b) |
| S203e | Silo A dry ash unloading – Units 1 & 2 | Baghouse (Shared with S203a) |

**Table 14 – P203 Emission Units Description**

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Ash Processed | 10.1 | | | Recordkeeping | Annually |
| PM & $PM_{10}$ | 10.2 | S203a<br>S203e<br>S203b<br>S203d | PM: 0.012 lb/ton<br>$PM_{10}$: 0.006 lb/ton | Recordkeeping and Calculation | Annually |
| | | F203c | PM: 0.0005 lb/ton<br>$PM_{10}$: 0.0002 lb/ton | | |
| Opacity | 10.3 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | EPA Reference Method 9<br>Bagfilter O&M | Semiannually<br>Ongoing O&M |
| 11MF332 Process Requirements | 10.4 | See Condition 10.4 | | | |

**Table 15 – P203 Emissions and Requirements Summary**

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

## 11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

| Facility Stack ID | Description | Pollution Control |
|---|---|---|
| S204a | Ash storage silo C – Unit 3 | Baghouse |
| F204b | Ash truck loading (wet flyash and dry flyash) – Unit 3 | Low dust loader (wet ash)<br>Baghouse (Only for dry fly ash loading) |
| S204c | Recycle ash tank | Baghouse |
| F204d | Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3 | $MgCl_2$ application on roads |

**Table 16 – P204 Emission Units Description**

| Parameter | Permit Condition Number | Limitation | | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|---|
| | | | | | Method | Interval |
| Ash Throughput | 11.1 | Unit 3 flyash handling: 174,649 tons/year<br><br>Unit 3 ash and scrubber sludge handling: 237,247 tons/year | | | Recordkeeping | Monthly |
| PM & $PM_{10}$ | 11.2 | S204a<br>S204c | PM: 76.6 tons/year (all units combined)<br><br>$PM_{10}$: 16.1 tons/year (all units combined) | PM: 0.012 lb/ton<br>$PM_{10}$: 0.006 lb/ton | Recordkeeping and Calculation | Monthly |
| | | F204b | | Flyash loading:<br>PM: 0.0005 lb/ton<br>$PM_{10}$: 0.0002 lb/ton<br><br>Dry ash unloading:<br>PM: 0.081 lb/ton<br>$PM_{10}$: 0.039 lb/ton<br>From AP-42, 13.2.4<br>Assume:<br>U = 8.1 mph,<br>M = 0.25% | |
| | | F204d | | PM: Paved: 6.39<br>Unpaved: 12.76<br>$PM_{10}$: Paved: 1.28 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | Unpaved: 3.6<br>EF in lb per vehicle mile traveled | | |
| Opacity | 11.3 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | | EPA Reference Method 9<br>Bagfilter O&M | Semiannually<br>Ongoing O&M |
| 12MF322-3 Process Requirements | 11.4 | See Condition 11.4 | | | | |

**Table 17 – P204 Emissions and Requirements Summary**

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, $PM_{10}$ emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

## 12. S401 & S402 – Units 1 & 2 Cooling Towers

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Circulating Water Rate | 12.1 | Maximum Pumping Capacity: 180,000 gallons/minute (per tower) | | Design Limitation Certification | Annually |
| Total Dissolved Solids | 12.2 | 11,040 milligrams/liter | | Sampling and Testing | Monthly |
| PM & $PM_{10}$ | 12.3 | PM: 27.2 tons/year<br>$PM_{10}$: 27.2 tons/year | TDS Sampling<br>See Condition 12.3 | Recordkeeping and Calculation | Annually |
| VOC | 12.4 | 5.0 tons/year | 0.0527 lb/$10^6$ gallons | Recordkeeping and Calculation | Annually |
| Opacity | 12.5 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | See Condition 12.5 | |

**Table 18 – S401 & S402 Emissions and Requirements Summary**

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and $PM_{10}$ emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

## 13. S403 – Unit 3 Cooling Tower

| Parameter | Permit Condition Number | Limitation | Compliance Emission Factor | Monitoring | |
|---|---|---|---|---|---|
| | | | | Method | Interval |
| Circulating Water Rate | 13.1 | Maximum Pumping Capacity: 180,000 gallons/minute | | Design Limitation Certification | Annually |
| Total Dissolved Solids | 13.2 | 11,040 milligrams/liter | | Sampling and Testing | Monthly |
| PM & $PM_{10}$ | 13.2.2 | PM: 13.6 tons/year<br>$PM_{10}$: 13.6 tons/year | TDS Sampling See Condition 13.2.2 | Recordkeeping and Calculation | Monthly |
| VOC | 13.4 | 2.5 tons/year | 0.0527 lb/$10^6$ gallons | Recordkeeping and Calculation | Monthly |
| Opacity | 13.5 | Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity | | See Condition 13.5 | |

**Table 19 – S403 Emissions and Requirements Summary**

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and $PM_{10}$ emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

**14. Emergency Diesel Engines**

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

*The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.*

*The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.*

*These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.*

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

**§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?**

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

**§63.6605 – What are my general requirements for complying with this Subpart?**

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

**§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?**

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

**§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?**

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

**§63.6655 – What records must I keep?**

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

**§63.6660 – In what form and how long must I keep my records?**

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

**§63.6665 – What parts of the General Provisions apply to me?**

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

**15. Colorado Regulation No. 1, Section II – Opacity**

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

**16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices**

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 $SO_2$ readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the $SO_2$ readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

**17. Particulate Matter Stack Testing**

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and $PM_{10}$ filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and $PM_{10}$ filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and $PM_{10}$ emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

**18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards**

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

## 19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the $NO_x$ (including diluents: $CO_2$ or $O_2$), $SO_2$, $CO_2$, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

### 19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **$SO_2$, $NO_x$ (and diluent), $CO_2$, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet $SO_2$ and $CO_2$ monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the $NO_x$ (including diluents: $CO_2$ or $O_2$), $SO_2$, $CO_2$, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **$SO_2$, $NO_x$, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

*Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.*

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and $SO_2$ emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

*Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for $NO_x$. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.*

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

## 19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30$^{th}$ day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The $SO_2$ CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of $SO_2$ per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the $SO_2$ emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the $SO_2$ limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average $NO_x$ concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average $NO_x$ emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, $SO_2$, $NO_x$, and $CO_2$ emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential $SO_2$ emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, $SO_2$, CEMS and coal sampling data, and $NO_x$ CEMS. The Source may not challenge the accuracy or credibility of their COMS, $SO_2$ CEMS and coal sampling data, and $NO_x$ CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

## 20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

**21. Emission Factors**

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

## 22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, $SO_2$), 2 (PM, $SO_2$, $NO_x$), and 3 (PM/$PM_{10}$, $SO_2$, $NO_x$), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of $SO_2$, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of $SO_2$ emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of $NO_x$, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of $NO_x$ emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/$PM_{10}$, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of $SO_2$, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of $SO_2$ emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of $SO_2$ emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of $NO_x$, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of $NO_x$ emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

## SECTION III - Acid Rain Requirements

### 1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

### 2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| $SO_2$ Allowances, per 40 CFR Part 73.10(b), Table 2 | C1: 7678<br>C2: 7352<br>C3: 2149 | C1: 7678<br>C2: 7352<br>C3: 2149 | C1: 7678<br>C2: 7352<br>C3: 2149 | C1: 7678<br>C2: 7352<br>C3: 2149 | C1: 7678<br>C2: 7352<br>C3: 2149 | C1: 7678<br>C2: 7352<br>C3: 2149 |
| $NO_X$ Limits | C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2)) | | | | | |

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

### 3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

## 4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

## 5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

## SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

### 1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

| Emission Unit Description & Number | Non-Applicable Requirement | Justification |
|---|---|---|
| B001 & B002 - Units 1 & 2 | Construction Permit 10MF579 reference to May 1, 1973 Subpart D | The Units are subject to the most current version of Subpart D. |
| Facility-Wide | Colorado Regulation No. 1, V | Applies to coke ovens at Iron and steel plant operations only. |
| | Colorado Regulation No. 1, VII | Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado |
| | Colorado Regulation No. 1, VIII | Applies to listed stationary sources in the Denver $PM_{10}$ nonattainment area only. |
| | Colorado Regulation No. 1, IX | Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide |
| | Colorado Regulation No. 4, and General Condition 31 of this permit | Sale and use of wood burning devices does not apply to the Craig Station |
| | Colorado Regulation No. 7, except for Part B, Section III | Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only. |
| | Colorado Regulation No. 8, Part D | Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision |
| | Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting | Subject matter does not cover the Craig facility. |
| | Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions | Subject matter does not cover the Craig facility. |
| | Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program | Subject matter does not cover the Craig facility. |

| | | |
|---|---|---|
| | Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions | Geographic area of applicability does not include the Craig facility. |
| | Colorado Regulation No. 13 - The Oxygenated Fuels Program | Area of geographic applicability does not include the Craig facility. |
| | Colorado Regulation No. 16 - Street Sanding | Geographic area of applicability does not include the Craig facility. |
| | 5CCR 1001-20 - Nonattainment Areas | Craig facility is not located in geographic areas classified as nonattainment. |
| | Colorado Regulation No. 19 - Lead Based Paint Abatement | Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards |
| | 40 CFR Part 55 - Outer Continental Shelf Air Regulations | Craig facility is outside the geographic scope of this provision. |
| | 40 CFR Part 56 - Regional Consistency | Relates to authorities within the various offices of the EPA. |

## 2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

## 3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

| Emission Unit Description & Number | Applicable Requirement | Justification |
|---|---|---|
| Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2) | Colorado SIP, April 19, 2001 – Definition of "boiler operating day" | The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent. |
| Section II, Conditions 3.2.2 & 3.3.3 | NSPS Da definition of "boiler operating day" | The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition. |
| Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2) | Colorado SIP, April 19, 2001 – Required quarterly reports | The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice. |
| Section II, Condition 3.6 (Unit 3) | 40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27% | This requirement is less strict than the BACT limit. |
| Section II, Condition 3.1 (Unit 3) | 40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu | This requirement is less strict than the BACT PM limit. |
| Section II, Condition 3.1 (Unit 3) | 40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements | Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit. |
| Section II, Condition 3.1 (Unit 3) | 40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits | Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits. |
| Section II, Condition 3.6 (Unit 3) | 40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations | The opacity condition has been streamlined out under BACT wherein records are already required |
| Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3) | Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu | This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits. |
| Section II, Condition 4 (Units 1, 2, & 3) | NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2) | So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements. |

| | | |
|---|---|---|
| Section II, Condition 13.1 | Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * $10^6$ gallons/year | This limit is merely the annualized PTE of the short term limit. |
| Section II, Condition 17.2 (Units 1 & 2) | Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing | Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent. |
| Section II, Condition 19 (Units 1, 2, & 3) | Colorado Regulation No. 1, Section IV – COMS and CEMS | The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements. |
| Section II, Condition 19 (Units 1, 2, & 3) | 40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS | The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements. |
| Section II, Condition 19 (Units 1 & 2) | Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 ($NO_x$, $SO_2$, $CO_2$, and flow) | The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements. |
| Section II, Condition 19 (Units 1 & 2) | Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2 | The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements. |

# SECTION V - General Permit Conditions (ver 1/21/2020)

**1. Administrative Changes**

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

**2. Certification Requirements**

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

**3. Common Provisions**

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

**4. Compliance Requirements**

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

**5. Emergency Provisions**

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

**6. Emission Controls for Asbestos**

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

**7. Emissions Trading, Marketable Permits, Economic Incentives**

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

**8. Fee Payment**

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

**9. Fugitive Particulate Emissions**

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

**10. Inspection and Entry**

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

**11. Minor Permit Modifications**

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

**12. New Source Review**

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

**13. No Property Rights Conveyed**

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

**14. Odor**

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

**15. Off-Permit Changes to the Source**

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

**16. Opacity**

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

**17. Open Burning**

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

**18. Ozone Depleting Compounds**

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

**19. Permit Expiration and Renewal**

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

**20. Portable Sources**

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

**21. Prompt Deviation Reporting**

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

**22. Record Keeping and Reporting Requirements**

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

**23. Reopenings for Cause**

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

**24. Requirements for Major Stationary Sources**

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

**25. Section 502(b)(10) Changes**

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

**26. Severability Clause**

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

**27. Significant Permit Modifications**

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

**28. Special Provisions Concerning the Acid Rain Program**

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

**29. Transfer or Assignment of Ownership**

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

**30. Volatile Organic Compounds**

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

**31. Wood Stoves and Wood burning Appliances**

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

# A. Appendix A - Inspection Information

## A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

## A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

## A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

## A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

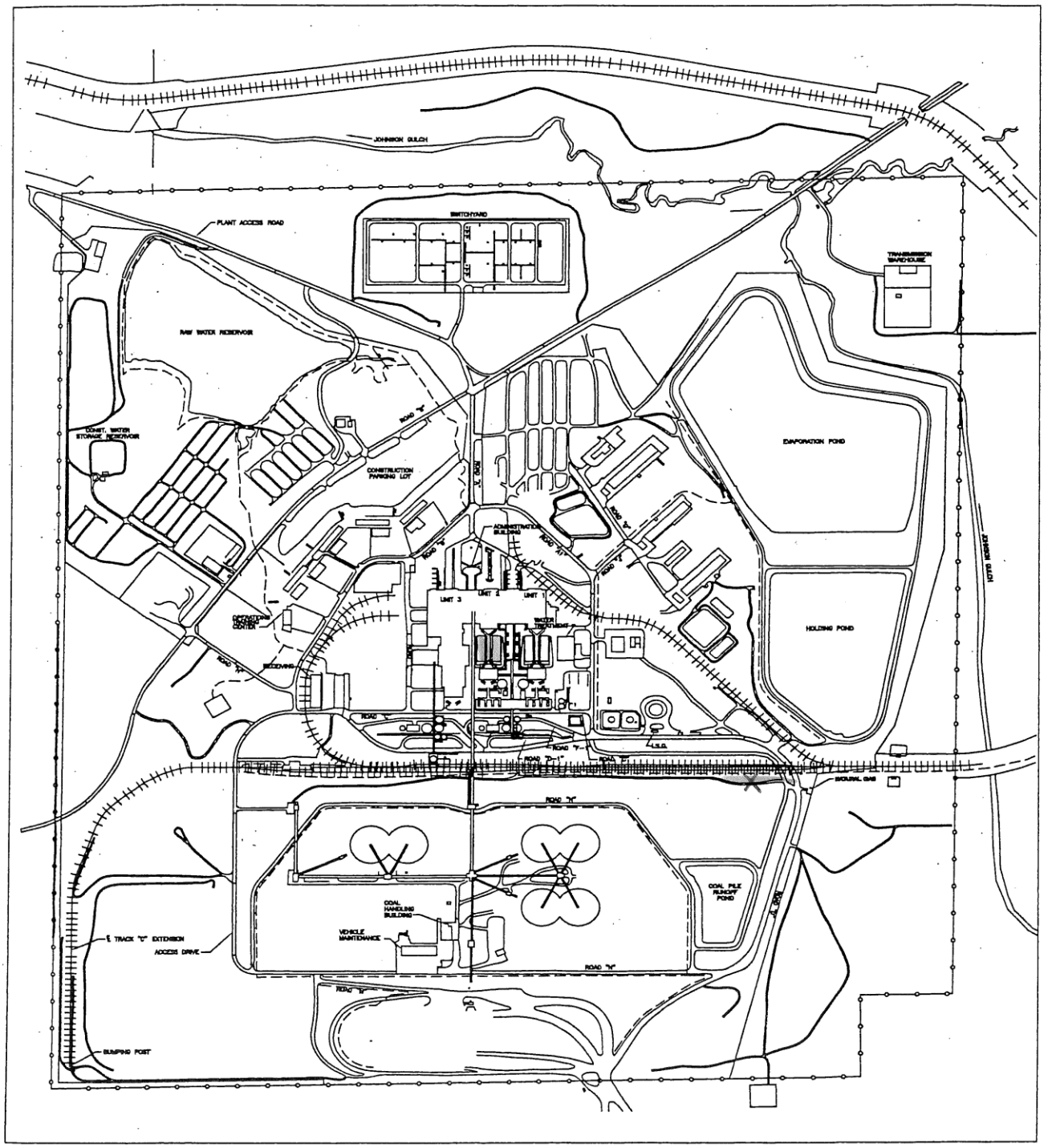
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

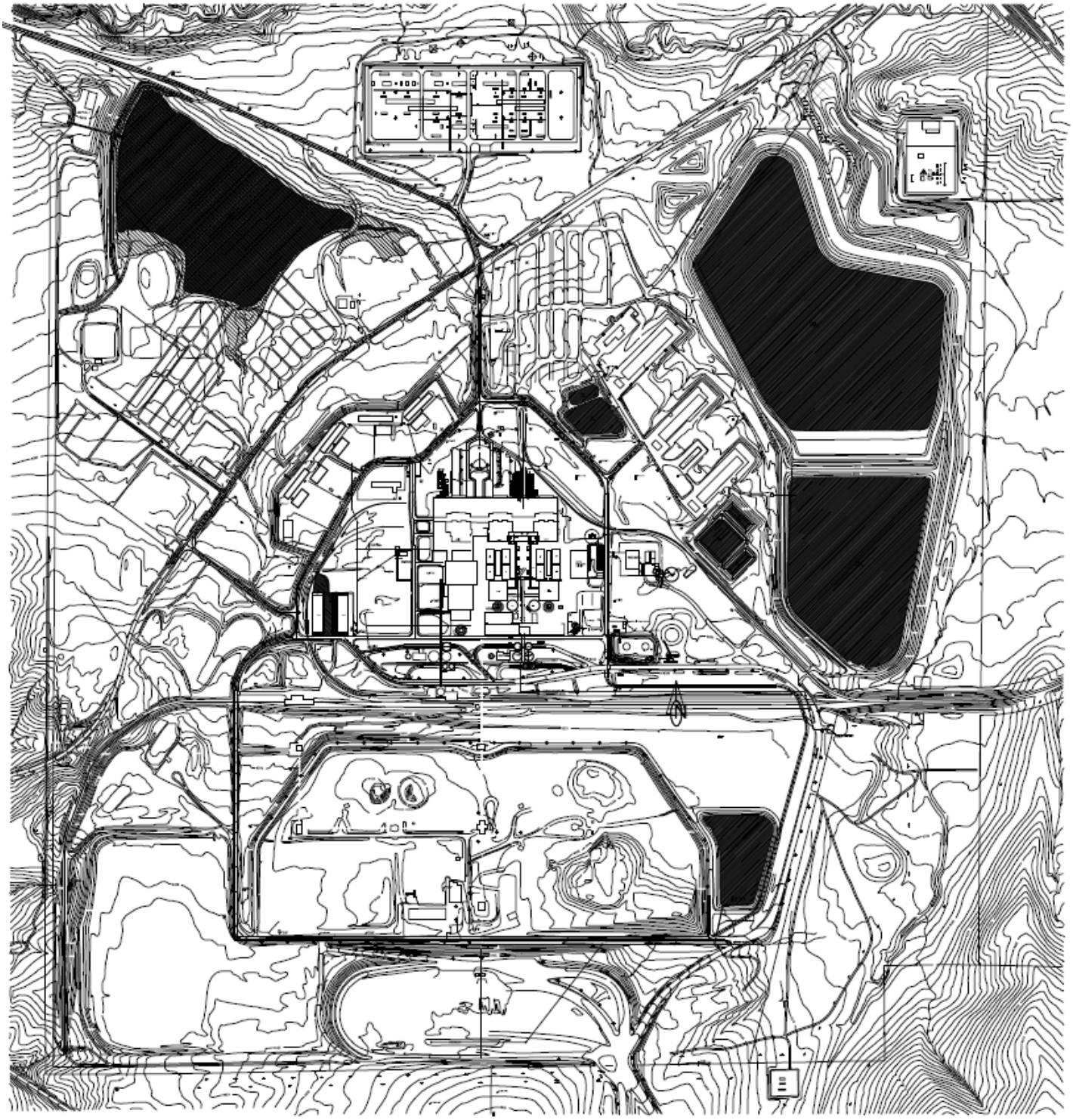
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
TRANSMISSION WAREHOUSE
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
EVAPORATION POND
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
HOLDING POND
RECEIVING
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
ROAD "I"
ROAD "J"
ROAD "K"
ROAD "L"
ROAD "M"
ROAD "N"
ROAD "O"
ROAD "P"
ROAD "Q"
ROAD "R"
ROAD "S"
ROAD "T"
ROAD "U"
ROAD "V"
ROAD "W"
ROAD "X"
ROAD "Y"
ROAD "Z"
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUNSPND POST



# B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

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The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

**Report #1: Monitoring Deviation Report** (due at least every six months)

*For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit.* All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

**Report #2: Permit Deviation Report (must be reported "promptly")**

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

*For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21.* Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

| | |
|---|---|
| **1 = Standard:** | When the requirement is an emission limit or standard |
| **2 = Process:** | When the requirement is a production/process limit |
| **3 = Monitor:** | When the requirement is monitoring |
| **4 = Test:** | When the requirement is testing |
| **5 = Maintenance:** | When required maintenance is not performed |
| **6 = Record:** | When the requirement is recordkeeping |
| **7 = Report:** | When the requirement is reporting |
| **8 = CAM:** | A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. |
| **9 = Other:** | When the deviation is not covered by any of the above categories |

**Report #3: Compliance Certification (annually, as defined in the permit)**

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

# Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

**Startup, Shutdown, and Malfunctions**

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

**Emergency Provisions**

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

**DEFINITIONS**

**Malfunction** (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

**Malfunction** (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

**Emergency** means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

## B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

| Emission Unit | Facility ID | Unit Description | Deviations noted During Period?[1] | | Deviation Code [2] | Malfunction/Emergency Condition Reported During Period? | |
|---|---|---|---|---|---|---|---|
| | | | YES | NO | | YES | NO |
| Unit 1 | B001 | Coal-Fired Boiler: Babcock & Wilcox #NB24157 | | | | | |
| Unit 2 | B002 | Coal-Fired Boiler: Babcock & Wilcox #NB24156 | | | | | |
| Unit 3 | B003 | Coal-Fired Boiler: Babcock & Wilcox #NB24602 | | | | | |
| Coal Handling – Units 1 & 2 | P101 | F101a – Coal hauling – Units 1 & 2 | | | | | |
| | | F101b – Coal unloading to grizzly – Units 1 & 2 | | | | | |
| | | F101c – Coal surge pile | | | | | |
| | | S101d – Primary coal crushing – Units 1 & 2 | | | | | |
| | | S101e – Secondary coal crushing building – Units 1 & 2 | | | | | |
| | | S101f – Common Coal Transfer Building Belt A | | | | | |
| | | S101g – Common Coal Transfer Building Belt B | | | | | |
| | | S101h – Coal stackout building – Units 1 & 2 | | | | | |
| | | F101i – Coal stackout – Units 1 & 2 | | | | | |
| | | F101j – Coal storage piles – Units 1 & 2 | | | | | |
| | | S101k – Coal reclaim A – Units 1 & 2 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | S101l – Coal reclaim B – Units 1 & 2 | | | | | |
| | | S101m – Coal tripper deck & silos – Units 1 & 2 | | | | | |
| Ash Handling – Units 1 & 2 | P203 | S203a – Ash storage silo A – Units 1 & 2 | | | | | |
| | | S203b – Ash storage silo B – Units 1 & 2 | | | | | |
| | | F203c – Ash truck loading – Units 1 & 2 | | | | | |
| | | S203d – Silo B dry ash unloading – Units 1 & 2 | | | | | |
| | | S203e – Silo A dry ash unloading – Units 1 & 2 | | | | | |
| Limestone Handling – Units 1 & 2 | P201 | F201a – Limestone hauling | | | | | |
| | | S201b – Limestone truck unloading | | | | | |
| | | S201c – Limestone silo #1 – Units 1 & 2 | | | | | |
| | | S201d – Limestone silo #2 – Units 1 & 2 | | | | | |
| Coal Handling – Unit 3 | P102 | F102a – Coal train unloading – Unit 3 | | | | | |
| | | S102b – Coal conveyor portal building – Unit 3 | | | | | |
| | | S102c – Coal conveyor portal building – Unit 3 | | | | | |
| | | S102d – Secondary coal crushing (2 crushers) – Unit 3 | | | | | |
| | | S102e – Coal stackout building – Unit 3 | | | | | |
| | | F102f – Coal stackout – Unit 3 | | | | | |
| | | F102g – Coal storage pile – Unit 3 | | | | | |
| | | S102h – Coal reclaim system – Unit 3 | | | | | |
| | | S102i – Coal tripper deck & silos – Unit 3 | | | | | |
| | | S102j – Loadout coal to railcars – Unit 3 | | | | | |
| | | S102k – Common coal transfer building extension | | | | | |
| | | F102l – Coal train loading | | | | | |
| Ash Handling – Unit 3 | P204 | S204a – Ash storage silo – Unit 3 | | | | | |
| | | F204b – Ash truck loading – Unit 3 | | | | | |
| | | S204c – Recycle ash truck | | | | | |
| | | F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3 | | | | | |
| Lime Handling – Unit 3 | P202 | F202a – Lime hauling | | | | | |
| | | S202b – Lime unloading | | | | | |
| | | S202c – Lime conveying and silo | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | S202d – Lime day bin | | | | | |
| Cooling Towers – Units 1 & 2 | P401 | Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74 | | | | | |
| | P402 | Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74 | | | | | |
| Cooling Tower – Unit 3 | P403 | Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79 | | | | | |
| Emergency Fire-Pump Engine | N/A | Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower | | | | | |
| Units 1&2 Emergency Diesel Generator | N/A | Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower | | | | | |
| Unit 3 Emergency Diesel Generator | N/A | Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower | | | | | |
| General Conditions | | | | | | | |
| Insignificant Activities | | | | | | | |

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

**1 = Standard:** When the requirement is an emission limit or standard
**2 = Process:** When the requirement is a production/process limit
**3 = Monitor:** When the requirement is monitoring
**4 = Test:** When the requirement is testing
**5 = Maintenance:** When required maintenance is not performed
**6 = Record:** When the requirement is recordkeeping
**7 = Report:** When the requirement is reporting
**8 = CAM:** A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
**9 = Other:** When the deviation is not covered by any of the above categories

**B.II. Appendix B – Monitoring and Permit Deviation Report - Part II**

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction ____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

**SEE EXAMPLE ON THE NEXT PAGE**

# EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

**B.III. Appendix B – Monitoring and Permit Deviation Report - Part III**

**REPORT CERTIFICATION**

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

**STATEMENT OF COMPLETENESS**

**I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.**

**Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.**

Printed or Typed Name Title

Signature of Responsible Official Date Signed

**Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.**

# C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

| Emission Unit | Facility ID | Unit Description | Deviations Reported [1] | | Monitoring Method per Permit?[2] | | Was compliance continuous or intermittent?[3] | |
|---|---|---|---|---|---|---|---|---|
| | | | Previous | Current | YES | NO | YES | NO |
| Unit 1 | B001 | Coal-Fired Boiler: Babcock & Wilcox #NB24157 | | | | | | |
| Unit 2 | B002 | Coal-Fired Boiler: Babcock & Wilcox #NB24156 | | | | | | |
| Unit 3 | B003 | Coal-Fired Boiler: Babcock & Wilcox #NB24602 | | | | | | |
| Coal Handling – Units 1 & 2 | P101 | F101a – Coal hauling – Units 1 & 2 | | | | | | |
| | | F101b – Coal unloading to grizzly – Units 1 & 2 | | | | | | |
| | | F101c – Coal surge pile | | | | | | |
| | | S101d – Primary coal crushing – Units 1 & 2 | | | | | | |
| | | S101e – Secondary coal crushing building – Units 1 & 2 | | | | | | |
| | | S101f – Common Coal Transfer Building Belt A | | | | | | |
| | | S101g – Common Coal Transfer Building | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Belt B | | | | | | |
| | | S101h – Coal stackout building – Units 1 & 2 | | | | | | |
| | | F101i – Coal stackout – Units 1 & 2 | | | | | | |
| | | F101j – Coal storage piles – Units 1 & 2 | | | | | | |
| | | S101k – Coal reclaim A – Units 1 & 2 | | | | | | |
| | | S101l – Coal reclaim B – Units 1 & 2 | | | | | | |
| | | S101m – Coal tripper deck & silos – Units 1 & 2 | | | | | | |
| Ash Handling – Units 1 & 2 | P203 | S203a – Ash storage silo A – Units 1 & 2 | | | | | | |
| | | S203b – Ash storage silo B – Units 1 & 2 | | | | | | |
| | | F203c – Ash truck loading – Units 1 & 2 | | | | | | |
| | | S203d – Silo B dry ash unloading – Units 1 & 2 | | | | | | |
| | | S203e – Silo A dry ash unloading – Units 1 & 2 | | | | | | |
| Limestone Handling – Units 1 & 2 | P201 | F201a – Limestone hauling | | | | | | |
| | | S201b – Limestone truck unloading | | | | | | |
| | | S201c – Limestone silo #1 – Units 1 & 2 | | | | | | |
| | | S201d – Limestone silo #2 – Units 1 & 2 | | | | | | |
| Coal Handling – Unit 3 | P102 | F102a – Coal train unloading – Unit 3 | | | | | | |
| | | S102b – Coal conveyor portal building – Unit 3 | | | | | | |
| | | S102c – Coal conveyor portal building – Unit 3 | | | | | | |
| | | S102d – Secondary coal crushing (2 crushers) – Unit 3 | | | | | | |
| | | S102e – Coal stackout building – Unit 3 | | | | | | |
| | | F102f – Coal stackout – Unit 3 | | | | | | |
| | | F102g – Coal storage pile – Unit 3 | | | | | | |
| | | S102h – Coal reclaim system – Unit 3 | | | | | | |
| | | S102i – Coal tripper deck & silos – Unit 3 | | | | | | |
| | | S102j – Loadout coal to railcars – Unit 3 | | | | | | |
| | | S102k – Common coal transfer building extension | | | | | | |
| | | F102l – Coal train loading | | | | | | |
| Ash Handling – Unit 3 | P204 | S204a – Ash storage silo – Unit 3 | | | | | | |
| | | F204b – Ash truck loading – Unit 3 | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | S204c – Recycle ash truck | | | | | | |
| | | F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3 | | | | | | |
| Lime Handling – Unit 3 | P202 | F202a – Lime hauling | | | | | | |
| | | S202b – Lime unloading | | | | | | |
| | | S202c – Lime conveying and silo | | | | | | |
| | | S202d – Lime day bin | | | | | | |
| Cooling Towers – Units 1 & 2 | P401 | Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74 | | | | | | |
| | P402 | Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74 | | | | | | |
| Cooling Tower – Unit 3 | P403 | Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79 | | | | | | |
| Emergency Fire-Pump Engine | N/A | Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower | | | | | | |
| Units 1&2 Emergency Diesel Generator | N/A | Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower | | | | | | |
| Unit 3 Emergency Diesel Generator | N/A | Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower | | | | | | |
| General Conditions | | | | | | | | |
| Insignificant Activities[4] | | | | | | | | |

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

**I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.**

**Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.**

Printed or Typed Name Title

Signature Date Signed

**NOTE:** All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

# D. Appendix D – Notification Addresses

## D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

## D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

# E. Appendix E – Permit Acronyms

Listed Alphabetically:

| | |
|---|---|
| AIRS - | Aerometric Information Retrieval System |
| AP-42 - | EPA Document Compiling Air Pollutant Emission Factors |
| APEN - | Air Pollution Emission Notice (State of Colorado) |
| APCD - | Air Pollution Control Division (State of Colorado) |
| ASTM - | American Society for Testing and Materials |
| BACT - | Best Available Control Technology |
| BTU - | British Thermal Unit |
| CAA - | Clean Air Act (CAAA = Clean Air Act Amendments) |
| CCR - | Colorado Code of Regulations |
| CEM - | Continuous Emissions Monitor |
| CF - | Cubic Feet (SCF = Standard Cubic Feet) |
| CFR - | Code of Federal Regulations |
| CO - | Carbon Monoxide |
| COM - | Continuous Opacity Monitor |
| CRS - | Colorado Revised Statute |
| EF - | Emission Factor |
| EPA - | Environmental Protection Agency |
| FI - | Fuel Input Rate in MMBtu/hr |
| FR - | Federal Register |
| G - | Grams |
| Gal - | Gallon |
| GPM - | Gallons per Minute |
| HAPs - | Hazardous Air Pollutants |
| HP - | Horsepower |
| HP-HR - | Horsepower Hour (G/HP-HR = Grams per Horsepower Hour) |
| LAER - | Lowest Achievable Emission Rate |
| LBS - | Pounds |
| M - | Thousand |
| MM - | Million |
| MMscf - | Million Standard Cubic Feet |
| MMscfd - | Million Standard Cubic Feet per Day |
| N/A or NA - | Not Applicable |
| NOx - | Nitrogen Oxides |
| NESHAP - | National Emission Standards for Hazardous Air Pollutants |
| NSPS - | New Source Performance Standards |
| P - | Process Weight Rate in Tons/Hr |
| PE - | Particulate Emissions |
| PM - | Particulate Matter |
| $PM_{10}$ - | Particulate Matter Under 10 Microns |
| PSD - | Prevention of Significant Deterioration |
| PTE - | Potential To Emit |

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
$SO_2$ - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

# F. Appendix F – Permit Modifications

| DATE OF REVISION | TYPE OF REVISION | SECTION NUMBER, CONDITION NUMBER | DESCRIPTION OF REVISION |
|---|---|---|---|
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# G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

## G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

## G.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | Visible Emissions (Opacity) |
| Measurement Approach | Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS). |
| II. Indicator Range | An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion.<br><br>In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary.<br><br>A history of the corrective action(s) will be maintained at the facility and made available upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75. |
| d. Monitoring Frequency | Continuous |
| e. Data Collection Procedures | Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13. |

## G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

## G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

## G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

# H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

## H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable $PM/PM_{10}$ requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons $PM_{10}$/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable $PM/PM_{10}$, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

## H.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | Visible Emissions (Opacity) |
| Measurement Approach | Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS). |

| | Indicator 1 |
|---|---|
| II. Indicator Range | An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion.<br><br>An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.<br><br>In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary.<br><br>A history of the corrective action(s) will be maintained at the facility and made available upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75. |
| d. Monitoring Frequency | Continuous |
| e. Data Collection Procedures | Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average. |

## H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

## H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

## H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

# I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

## I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

## I.II. Monitoring Approach

| | Indicator 1 | Indicator 2 |
|---|---|---|
| I. Indicator | Visible Emissions | Differential Pressure Monitoring |
| Measurement Approach | Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active. | The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold. |

| | Indicator 1 | Indicator 2 |
|---|---|---|
| II. Indicator Range | An excursion is defined as any visible emissions seen during the Method 22 test.<br>When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary.<br>A history of the corrective action(s) will be maintained at the facility and made available upon request. | An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water.<br>When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary.<br>A history of the corrective action(s) will be maintained at the facility and made available upon request. |
| III. Performance Criteria | | |
| a. Data Representativeness | Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions. | Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device. |
| b. Verification of Operational Status | The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation. | The pressure measurement system will alert the operator if the system is not functioning properly. |
| c. QA/QC Practices and Criteria | Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained. | The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source. |
| d. Monitoring Frequency | Monthly | Daily |
| e. Data Collection Procedures | The EPA Reference Method 22 procedures shall be followed. | The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged. |
| f. Averaging Time | N/A | N/A |

## I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

## I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

## I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

# J. Appendix J – Units 1 and 2 Wet Limestone $SO_2$ Scrubbers Compliance Assurance Monitoring Plan

## J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable $SO_2$ requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous $SO_2$ emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control $SO_2$ emissions.

## J.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | $SO_2$ Emissions |
| Measurement Approach | $SO_2$ emissions will be monitored using a continuous emissions monitoring system (CEMS) |

| | Indicator 1 |
|---|---|
| II. Indicator Range | An excursion is defined as any 30-day average of $SO_2$ emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | $SO_2$ emissions are measured at the stack outlet. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75. |
| d. Monitoring Frequency | Continuous |
| e. Data Collection Procedures | $SO_2$ emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages. |

## J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control $SO_2$ emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with $SO_2$ in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

## J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with $SO_2$ CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the $SO_2$ Regional Haze limits is acceptable monitoring for CAM.

## J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

# K. Appendix K – Unit 3 Lime Spray Dryer $SO_2$ Compliance Assurance Monitoring Plan

## K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable $SO_2$ requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of $SO_2$, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of $SO_2$ per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain $SO_2$ emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous $SO_2$ emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control $SO_2$ emissions.

## K.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | $SO_2$ Emissions |
| Measurement Approach | $SO_2$ emissions will be monitored using a continuous emissions monitoring system (CEMS) |
| II. Indicator Range | An excursion is defined as any 30-day average of $SO_2$ emissions that exceed 0.15 lb/MMBtu or any daily average of $SO_2$ emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | $SO_2$ emissions are measured at the stack outlet. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75. |
| d. Monitoring Frequency | Continuous |
| e. Data Collection Procedures | $SO_2$ emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages. |

## K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control $SO_2$ emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with $SO_2$ in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

## K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an $SO_2$ CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the $SO_2$ BACT and Regional Haze limits are acceptable monitoring for CAM.

## K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

# L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

## L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable $NO_x$ requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous $NO_x$ emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of $NO_x$ emissions.

## L.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | $NO_x$ Emissions |
| Measurement Approach | $NO_x$ emissions will be monitored using a continuous emissions monitoring system (CEMS) |
| II. Indicator Range | An excursion is defined as any 30-day average of $NO_x$ emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | $NO_x$ emissions are measured at the stack outlet. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75. |
| d. Monitoring Frequency | Continuous |

| | Indicator 1 |
|---|---|
| e. Data Collection Procedures | $NO_x$ emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages. |

## L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control $NO_x$ emissions.

L.III.1.ii. $NO_x$ emissions are chemically reduced to $N_2$ and $H_2O$ using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

## L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a $NO_x$ CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the $NO_x$ Regional Haze limits are acceptable monitoring for CAM.

## L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

# M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

## M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable $NO_x$ requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous $NO_x$ emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of $NO_x$ emissions.

## M.II. Monitoring Approach

| | Indicator 1 |
|---|---|
| I. Indicator | $NO_x$ Emissions |
| Measurement Approach | $NO_x$ emissions will be monitored using a continuous emissions monitoring system (CEMS) |
| II. Indicator Range | An excursion is defined as any 30-day average of $NO_x$ emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request. |
| III. Performance Criteria | |
| a. Data Representativeness | $NO_x$ emissions are measured at the stack outlet. |
| b. Verification of Operational Status | Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS). |
| c. QA/QC Practices and Criteria | The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75. |
| d. Monitoring Frequency | Continuous |

| | Indicator 1 |
|---|---|
| e. Data Collection Procedures | $NO_x$ emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS. |
| f. Averaging Time | CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages. |

## M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control $NO_x$ emissions.

M.III.1.ii. $NO_x$ emissions are chemically reduced to $N_2$ and $H_2O$ using ammonia injected into the exhaust stream.

## M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a $NO_x$ CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the $NO_x$ Regional Haze limits are acceptable monitoring for CAM.

## M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

# N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

## N.I. Coal Sampling

### N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

### N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

### N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

**N.II. Sample Preparation and Laboratory Analyses**

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

**N.III. Chain-Of-Custody Method**

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

**N.IV. Coal Shipment and Sample Analysis Records**

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit LL: Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)

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# TECHNICAL REVIEW DOCUMENT
# for
# OPERATING PERMIT 96OPMF155

to be issued to:

Tri-State Generation & Transmission Association
**Craig Station**
Moffat County
Source ID 0810018

Cathy Rhodes
May, 2002
Revised January, 2005

## I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. This narrative is intended only as an adjunct for the reviewer and has no legal standing. The conclusions made in this report are based on information provided in the original application submittal of February 23, 1996 and the revised application submittal of January 4, 1999, and additional information received on October 21, 1999 and August 31, 2001.

Any revisions made to the underlying construction permits associated with this facility in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or an additional or revised Construction Permit.

## II. SOURCE DESCRIPTION:

This facility is located in Craig, Moffat County, Colorado. The area is classified as an attainment area for all pollutants. Wyoming is an affected state within 50 miles of the facility. There are two Federal Class I areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument, although not a Class I area, is within 100 kilometers of the facility, and has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

The entire plant is categorized as a major stationary source for the Prevention of Significant Deterioration (PSD) provisions. The EPA issued a PSD permit for Unit 3 on March 26,

1980. Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part A, Section I.B.37 and 58) for any pollutant listed in Colorado Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

The Craig Station consists of three coal fired steam driven electric generating units (Units 1, 2, and 3). Total net electric generating capacity is 1264 MW. Natural gas, propane and fuel oil are used as secondary fuels for flame stabilization, startup and shutdown. All three units are subject to the provisions of Title IV, the Acid Rain Program, of the Clean Air Act. Units 1 & 2 PM emissions were controlled by ESPs and wet limestone scrubbers control $SO_2$ emissions. Under a January 10, 2001 Consent Order, the ESPs have been replaced with baghouses and the wet scrubbers were upgraded. A baghouse controls PM emissions, and a spray dry scrubber controls $SO_2$ emissions from Unit 3. All three units have low-$NO_x$ burners to control $NO_x$ emissions. Overfire air and related $NO_x$ control upgrades are now in place for Unit 1 and Unit 2. This permit currently only covers Units 1 and 2 and associated equipment. This permit does not currently cover Unit 3 or its associated equipment (except for coal handling, which may at times also serve Units 1 and 2). Associated activities covered by the permit include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area, as well as numerous insignificant activities.

Unit 3 is currently operating under the provisions of an EPA-issued PSD permit (issued on March 26, 1980, revised January 12, 1981, and August 14, 1992) and State-issued Construction permits 12MF322(1-4) and 98MF0141. The draft version of this permit that went to Public Comment on May 17, 2001 as well as the Proposed version of the permit that went to EPA on September 13, 2004 covered all three boilers. Prior to the Public Comment period, EPA, the Division, and Tri-State had discussions regarding the interpretation of several conditions of the EPA PSD permit. Following Public Comment, discussions continued on two issues: Range Z and the applicability of the BACT limits during periods of startup, shutdown, and malfunction (s/s/m). The root of the issues lies with imprecise and confusing language that was put into the PSD permit when it was issued some 25 years ago. Some of the issues were not resolved, and EPA sent a formal objection letter to the Division on October 22, 2004, citing the remaining unresolved issues. Under the provisions of Regulation No. 3, Part C, § VI.H, the Division has 90 days in which to submit a revised permit to EPA after a formal objection letter is received. During the 90 day period, Tri-State indicated that they were planning on submitting an application to the Division for a major PSD modification to Unit 3 sometime in April 2005. State statutes and Federal regulations provide for the Air Pollution Control Division ("APCD") to issue PSD permits for major modifications made after September 2, 1986. Section 25-7-210 C.R.S. states:

> Sections 25-7-201 and 25-7-203 to 25-7-206 shall apply only to applications for proposed new major stationary sources and major modifications which are submitted on or after the date of approval by the United States

environmental protection agency of the program for prevention of significant deterioration embodied in the state implementation plan.

Thus the March application will result in a new PSD Construction permit for Unit 3 and associated activities. The new permit will replace the existing PSD permit, and will address the provisions upon which the EPA's objection was based.

Since a new PSD permit will be issued in the near future, the Division and the EPA have agreed that the Division will at this time issue a revised Operating Permit which contains only the requirements for Units 1 and 2. The Unit 3 requirements will be added to this operating permit once the new PSD permit is issued. The EPA and the Division believe that this is the best and most expedient method to resolve the existing PSD permit concerns and the EPA objections regarding the initially proposed operating permit. The new PSD permit will be issued using the appropriate procedures in Regulation No. 3, including public notice and participation requirements. Under Regulation No. 3, Part C provisions, the applicant must apply for a modification to incorporate the new PSD permit requirements into their operating permit within twelve months of startup of the modified Unit 3. The revised Operating Permit will be issued using the Significant Modification procedures of Regulation No. 3, Part C, including public notice and participation requirements and EPA review.

The following Potential-to-Emit and actual 1997 emissions data are based on information supplied in the Title V application (rounded figures – includes all three units and all associated activities).

| | **POTENTIAL TO EMIT, TONS PER YEAR** | | | | | |
|---|---|---|---|---|---|---|
| | PM | $PM_{10}$ | $SO_2$ | $NO_X$ | VOC | CO |
| B001 - Unit 1 | 1891 | 435 | 22695 | 13239 | 60 | 498 |
| B002 - Unit 2 | 1891 | 435 | 22695 | 13239 | 60 | 498 |
| B003 - Unit 3 | 566 | 130 | 3770 | 9426 | 58 | 484 |
| P101 - Coal Handling Units 1 & 2 | 41 | 18 | | | | |
| P102 - Coal Handling Unit 3 | 2 | 1 | | | | |
| P201 - Limestone Handling Units 1 & 2 | 14 | 3 | | | | |
| P202 - Lime Handling Unit 3 | 23 | 6 | | | | |
| | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| P203 - Ash Handling Units 1 & 2 | neg | Neg | | | | |
| P204 - Ash Handling and Ash Haul Roads Unit 3 | 115 | 30 | | | | |
| P205 – Landfill | 4 | 1 | | | | |
| P401 - Unit 1 CT | 14 | 14 | | | 5 | |
| P402 - Unit 2 CT | 14 | 14 | | | 5 | |
| P403 - Unit 3 CT | 14 | 14 | | | 5 | |
| Total | 4588 | 1101 | 49160 | 35904 | 194 | 1479 |
| FACILITY 1997 ACTUAL EMISSIONS TPY | 772 | 250 | 10094 | 15750 | 133 | 1110 |

CT = Cooling Tower

## III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

**B001 - Unit #1 - Babcock & Wilcox Boiler**
**B002 – Unit #2- Babcock & Wilcox Boiler**

**Applicable Requirements** - Final Approval Construction Permit 10MF579 was issued for Units 1 and 2. Applicable requirements are as follows.

Construction Permit 10MF579

- This source is subject to the requirements of the New Source Performance Standards for Fossil Fuel Fired Steam Generators, as in effect May 1, 1973.

  *Construction Permit 10MF579 indicates that the Units are subject to the NSPS as it existed on May 1, 1973. This is because the units were permitted when Subpart D was in the proposal process, and had not been finalized by the EPA. Subsequently, the EPA finalized the rule, and it applies to all sources constructed, reconstructed, or modified after August 17, 1971. The rule does not provide for any exceptions for sources constructed prior to final promulgation, therefore, Units 1*

*and 2 are subject to the most current version of Subpart D. This revision to the Construction Permit is incorporated directly into this operating permit through a combined Construction Permit/Operating Permit procedure. Note: The EPA did not promulgate startup, shutdown, and malfunction provisions until October 15, 1973.*

- Emissions of sulfur dioxide shall not exceed 1.2 pounds per million Btu heat input, maximum 3 hour average.

- Visible emissions shall not exceed 20 percent opacity.

- Emissions of particulate matter shall not exceed 0.1 pounds per million Btu heat input, maximum 2 hour average. *On June 14, 1974, the EPA revised Subpart D to change the sampling time requirements for PM from a minimum of 2 hours to a minimum of 60 minutes per run, to make the provision consistent with 60.8(f). The sampling interval specified in 60.46 was shortened to be consistent with the 60-minute-per-run requirement. The preamble to this revision states that these actions are intended for clarification and for maintaining consistency throughout the regulations. They are not intended to alter the substantive content of the regulations. Thus, the 2 hour averaging time no longer applies to Units 1 and 2.*

- Emissions of nitrogen oxides shall not exceed 0.7 pounds per million Btu heat input, maximum 3 hour average.

- This source shall comply with all applicable monitoring, notification, and record keeping requirements of the New Source Performance Standards (Regulation 6) and Regulation 1. IV.

- This source is subject to the requirements of Regulation 6. Section I., including Section I.4 which states: At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

- A Revised Air Pollutant Emission Notice shall be filed when a significant change in emissions occurs, as required by Regulation No.3.II.B.

Colorado Regulation No. 1

- Except as provided in Section II.A.4, opacity shall not exceed 20% (Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or cleaning of control equipment (Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu heat input (Section III. A.1.c)
- Continuous emission monitoring (Section IV)
- Continuous Opacity Monitor (COM) requirements (Section IV.B.1)
- Continuous Emission Monitor (CEM) for $SO_2$ or fuel sampling (Section IV.B.2)
- If CEM for $SO_2$ then CEM for either $O_2$ or $CO_2$ (Section IV.B.3)
- Calibration of CEMs (Section IV.F)
- Notification and Recordkeeping (Section IV.G)
- Recordkeeping duration (Section IV.H)
- Reporting requirements - if fuel sampling (Section IV.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu heat input (Section VI.A.3.a.(ii)), based on a 3 hour rolling average

Colorado Regulation No. 8, Part C

- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 μg/scm averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement

NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)

- Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu heat input
- Opacity shall not exceed 20%, except for one six-minute period of not more than 27% - does not apply during start-up, shutdown and malfunction
- $SO_2$ emissions shall not exceed 1.2 lbs/mmBtu heat input when burning coal, 3 hour average
- $NO_X$ emissions shall not exceed 0.70 lbs/mmBtu heat input when burning coal, 3 hour average

- Source shall install, calibrate, maintain and operate continuous monitoring systems for measuring opacity, $SO_2$ and $NO_X$ emissions and either $O_2$ or $CO_2$

*PM, $SO_2$, and $NO_x$ emission limits do not apply during startup, shutdown, or malfunction. (See October 15, 1973 Federal Register)*

Acid Rain (Title IV) Requirements

- The Code of Federal Regulations lists 8153 (Unit 1) and 7785 (Unit 2) $SO_2$ allowances (as listed in 40 CFR 73.10(b)) for these sources. Note that additional allowances can be obtained as needed per 40 CFR Part 75. The units will be allocated 8153 and 7785 allowances per year from 2000 to 2009 (as listed in the EPA's "Allowances Held Report," January 4, 1999).
- $NO_x$ emissions of 0.50 lbs/mmBtu heat input, on an annual average basis (source opted to comply with Phase I limits (§76.5(a)(2) by early election (§ 76.8), which went into effect January 1, 1997).
- Acid rain permitting requirements per 40 CFR Part 72.
- Continuous emission monitoring requirements per 40 CFR Part 75.
- The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

January 10, 2001 Consent Decree Requirements

- Requires replacement of ESPs at Units 1 and 2 with baghouses, FGD upgrades, and installation of $NO_x$ emission control upgrades by certain dates
- PM emissions from Units 1 and 2 shall not exceed 0.03 lb/mmBtu heat input by certain dates
- $SO_2$ emissions from Units 1 and 2 shall not exceed 0.160 lb/mmBtu heat input, on a 30 day rolling average and 0.130 lb/mmBtu heat input on a 90 day rolling average, by certain dates
- $SO_2$ emissions from Units 1 and 2 shall be controlled by either 86% on a 30 day rolling average, or 90% on a 90 day rolling average, by certain dates, unless a "showing" is made
- $NO_x$ emissions from Units 1 and 2 shall not exceed 0.30 lb/mmBtu heat input on an annual average basis, by certain dates
- Limits opacity as follows: (1) 20% averaged over each separate 6-minute period at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for more than 6 minutes in any 60 consecutive minutes; (2) 30% for more than 6 minutes during any 60 consecutive minutes during any startup; (3) 20% during any

shutdown, unless excused by an upset condition; (4) 20% except for one six minute period per hour of not more than 27% opacity as averaged over each separate 6-minute period with an hour, beginning each hour on the hour. Emissions during startup, shutdown and malfunction are excused under this opacity limit.

- Requires stack testing for PM
- Requires installation and operation of continuous opacity monitors and continuous monitors for $SO_2$ emissions, $NO_x$ emissions, $CO_2$, and flow
- Requires permittee to operate Units 1 and 2 using good operating practices

Note: Since this permit went to public notice, the milestones for various Consent Decree requirements have passed. The permit is therefore revised to delete those due dates and obsolete requirements related to the ESPs.

**Consent Decree Requirements as a Pollution Control Project**

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the FGD upgrades do not result in an increase in emissions. The $NO_X$ emission control upgrades may decrease $NO_X$ emissions substantially but increase CO emissions slightly. In the case of Craig Units 1 and 2, the addition of control equipment is required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NOx emission control upgrades. Therefore, the Division does not believe it is appropriate to include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the $NO_X$ emission control upgrades.

**Effect of Incorporation of Consent Decree into the Operating Permit**

The Consent Decree requirements were approved by the EPA as part of the Colorado State implementation Plan and are applicable requirements which must be included in the operating permit. Under terms of the Consent Decree, upon issuance of this operating permit, the Division assumes certain compliance/enforcement provisions of the Decree. As for any applicable requirement incorporated into an operating permit, nothing in the permit is intended to have the effect of relaxing any requirement in the Consent Decree or to change or modify any rights of the parties to that decree.

**Voluntary Emission Reduction Agreement (VERA)**

In 2001, a VERA was completed for Units 1 and 2, to reduce emissions which affect visibility and air quality related values. VERA's normally include specific emission limits and related requirements, and are included as applicable requirements in operating permits. In this case, the VERA states that the Division finds and determines that the provisions of the Consent Decree meet the requirements for a VERA for Units 1 and 2. Therfore, this VERA

is not incorporated into the operating permit, since the Consent Decree requirements are incorporated.

**Emission Factors -** The combustion of coal in the boilers results in emissions of $NO_x$, $SO_2$, PM, $PM_{10}$, CO, VOC, and Pb. CEMs are used to determine compliance with emission standards and to estimate annual emissions of $NO_x$, and $SO_2$. For PM and $PM_{10}$, stack test results and monitored heat content of the fuel are used to determine compliance and estimate annual emissions. Standard factors from the AP-42 manual, or other emission factors/procedures acceptable to the Division (see Regulation No. 3, Part A, II.B.1 for acceptable alternative methods) along with appropriate removal efficiencies for control equipment, are used to estimate CO, VOC, HAP and Pb emissions.

**Monitoring Plan -** CEMs are used to demonstrate compliance with the $NO_x$ and $SO_2$ lb/mmBtu limits. Stack testing and a baghouse and wet scrubber maintenance plan are used to demonstrate compliance with the PM limits. The required frequency for PM stack testing will be reduced, if the source meets criteria based on the test results in relation to the emission standard, as set forth in the permit. The heat content of the fuel is needed for these determinations. The heat input can be calculated from the carbon dioxide CEM required under the Acid Rain Program, or measured through a coal sampling plan, or vendor information.

Compliance with opacity limits is demonstrated using a COM.

Scales are used to measure the amount of coal combusted in the boiler. These data are used to estimate PM, $PM_{10}$, CO, VOC, and HAP emissions.

The permittee performed a one-time modeling exercise which demonstrated compliance with the Regulation No. 8 lead requirements.

**Compliance Status** - The Division accepts these Units were in compliance at the time the Title V application was submitted. In addition, the most recent inspection report indicates the Units were in compliance at the time of inspection.

**B001 - Unit #1 - Babcock & Wilcox Boiler - Natural Gas, Propane, and Fuel Oil**
**B002 - Unit #2 - Babcock & Wilcox Boiler - Natural Gas, Propane, and Fuel Oil**

Coal is the primary fuel for these boilers. Secondary fuels (natural gas, propane, or fuel oil) are used during non-routine periods such as startup and shutdown, adding to or removing coal pulverizers from service, or other flame stability efforts.

**Applicable Requirements -** The Construction Permit did not address secondary fuels. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion. The

permittee submitted information which indicates that, for the past five years, “alternative” fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas, propane or fuel oil remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 5% of total heat input. If alternate fuel use comprises more than 5% of total heat input on an annual basis, the permit must be reopened to include Subpart D requirements for combined fuel combustion. In addition, this source is subject to Regulation No. 1 emission limits, which are equal to or less stringent than Subpart D provisions. The Division therefore also assumes the source is in compliance with Regulation No. 1 requirements whenever alternate fuel use comprises less than 1% of total heat input.

**Alternate Operating Scenarios**

The permittee requested the ability to dispose of spent boiler tube cleaning waste as an alternate operating scenario. Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. The cleaning is accomplished by circulating cleaning solutions, generally acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. The permittee had previously requested to dispose of cleaning waste in the boiler, in March of 1993. At that time the Division agreed to the proposal, and determined a modification to the Construction Permit was not necessary. The permittee provided information regarding studies performed by the Electric Power Research Institute which indicates that disposal of cleaning wastes does not have a significant effect on operations or emissions. This has been an on-going practice for boilers operated by utilities, and has not been cited by the Division as a compliance issue.

In addition, the permittee indicates that on a sporadic basis, they wish to combust non-hazardous petroleum contaminated soils and materials in the boiler. These materials are generated on occasions at the Craig Station when accidental spills of petroleum liquids (lube oils and fuel) occur. Because of the expected small quantity of non-hazardous petroleum contaminated soils and materials generated, it is expected that introduction of such materials into the boiler for combustion will not cause the exceedance of any applicable emission limit or emission of pollutants not generated by routine operation of these boilers.

Provisions for these two alternate operating scenarios are provided for in the Operating Permit.

**P101 – Coal Handling – Units 1 & 2**

The Unit 1 and 2 coal handling system transfers coal delivered by trucks on unpaved haul roads to Craig Station to the Unit 1, 2, and 3 coal storage piles and silos. On occasion, coal is deposited in a coal surge pile prior to being transferred to the crusher. The coal is

crushed and conveyed to the coal transfer building, where it is sent either to the stockpiles or coal silos. Coal destined for the storage pile is conveyed to the stackout tower and then to telescoping chutes for loadout to the storage pile. Coal is reclaimed underground from storage and is transferred to generation building coal silos. Bagfilters and enclosed conveyors control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles. Telescopic chutes are used to control PM emissions from the coal pile stackout. Coal unloading and stackout is controlled with water spray containing a surfactant, on an as-needed basis. Note that water sprays may not be operable during cold weather. The coal haul road is treated with a resinous adhesive, or equivalent, as often as necessary.

**Applicable Requirements** - Final Construction Permit 11MF276 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF276

- Limits process throughput to 3,900,000 tons per year
- Limits opacity to 20%
- Sets forth measures for minimizing fugitive particulate matter emissions

  Requested revisions:

  "The coal being loaded to live storage will be sprayed with water with a surfactant added," is revised to read: "The coal being loaded to live storage will be sprayed with water with a surfactant added, on an as-needed basis." This is consistent with other Tri-State construction permits.

  "The haul road used by coal trucks on the Craig Station property shall be treated with a resinous adhesive (or equivalent) to control dust. The treatment material shall be bladed into the soil according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure." Is revised to read: "The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure."

  The requirement for water spray bars at the unloading station is revised to indicate that the spray bars will be used *as needed*.

Regulation No.1.II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

*(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." The Division has determined that the emissions from the coal pile stackout telescopic chute are fugitive.) Other fugitive sources include the storage piles, unloading to the grizzly, unloading to the coal surge pile, and the haul road.*

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% for all sources except the storage piles, unloading to coal surge pile, coal pile stackout and coal stackout building, coal reclaim A & B, coal tripper deck and silos, common coal drive house, and haul roads - Not applicable during startup, shutdown, or malfunction

**Emission Factors** - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions.

**Monitoring Plan -** As-fired and as-received belt scales continuously weigh the coal as it moves from the truck unloading hoppers to the units or stockpile, and from the stockpile to the coal silos. These monitoring records can be used to identify compliance with the coal handling limits. The emissions are calculated based on the amount of coal being processed.

For those sources subject to an opacity standard, a U.S. EPA Reference Method 9 opacity observation is performed by a certified observer at least semi-annually. An operation and maintenance plan shall be implemented for the baghouses.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

**Compliance Status** - The Division accepts this process was in compliance at the time the Title V application was submitted.

**P102 – Coal Handling – Unit 3**

The Unit 3 coal handling system transfers coal delivered by rail car to the Unit 1,2, and 3 coal piles and silos. Coal drops from the railcars into underground hoppers and is conveyed to the crusher building. After crushing, coal is conveyed to the stackout building, where it is either sent to the stockpile or to the transfer building. Coal in the transfer building is conveyed to the coal silos in the generation building. Bagfilters control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles.

Telescopic chutes are used to control PM emissions from the coal pile stackout. Water is sprayed at the coal train unloading to control PM emissions. Note that water sprays may not be operable during cold weather. Water, compaction or chemicals are used, as necessary, to control PM emissions at the coal storage piles. Since the Unit 3 system handles coal which may be delivered to Units 1 and 2, the system is included in the Operating Permit at this time.

**Applicable Requirements** - Final Construction Permit 12MF322(2) was issued for these sources. Applicable requirements are as follows.

Construction Permit 12MF322(2)

- Limits opacity to 20%
- Sets forth measures for minimizing fugitive PM emissions
- Requires emissions from crushing, transferring, and coal reclaiming to be controlled by fabric filter baghouses

Colorado Regulation No.1.II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes *(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." Fugitive sources include coal train unloading, coal stackout, and storage piles.)*

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% - Not applicable during startup, shutdown, or malfunction - Does not apply to coal stackout, common coal transfer building extension, common coal drive house, coal tripper deck and silos, to the storage pile, or to the open coal storage pile

Other

The Construction Permit does not contain a specific processing limit, however, records of the amount of coal processed are necessary for estimating emissions.

**Emission Factors** - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions.

**Monitoring Plan -** As-fired and as-received belt scales continuously weigh the coal as it moves from the rail cars unloading hoppers to the Units or stockpile, and from the stockpile to the coal silos. The emissions are calculated based on the amount of coal being processed. A U.S. EPA Reference Method 9 opacity observation is performed by a certified observer every six months and a baghouse operating and maintenance plan is required.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

**Compliance Status** - The Division accepts the process was in compliance at the time the Title V application was submitted.

**P201 – Limestone Handling and Storage Facility – Units 1 & 2**

The Unit 1 & 2 limestone handling system provides for receiving, transferring, storage, and preparation of limestone before it is introduced to the Units 1 & 2 wet limestone scrubbers. Limestone is delivered by trucks, and unloaded to a receiving hopper. Limestone is then transferred to the silos. Bagfilters are used to control PM emissions at the silo and unloading.

**Applicable Requirements** - Final Construction Permit 11MF415 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF415

- Limits opacity to 20%
- Requires unloading facilities emissions to be controlled by baghouse

Construction Permit requirement is revised from: “All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system.” To: “All process equipment shall be maintained and operated so as to minimize leakage of air contaminents to the atmosphere prior to their treatment in the pollution control system.”

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

Does not apply to fugitive emission sources: limestone hauling.

Other

The Construction Permit does not specifically limit the amount of limestone delivered, however, the amount is needed to calculate emissions estimates

**Emission Factors** - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions

**Monitoring Plan** -Semi-annual U.S. EPA Reference Method 9 opacity observations will be performed on the baghouses and a baghouse operation and maintenance plan is required.

**Compliance Status** - The Division accepts the units were in compliance at the time the Title V application was submitted.

**P203 – Ash Handling System – Units 1 & 2**

The Unit 1 and 2 ash handling and processing system provides for transferring ash from the boilers and ESPs to ash silos for temporary storage before it is transported for off-site disposal or commercial sale. The Unit 1 and 2 boilers generate both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Fly ash is pneumatically transported to the silos. Bagfilters are used to control PM emissions for the silos and the dry ash unloading for commercial sale. Water and dustless unloaders are used to control PM for truck loading operations for ash disposal.

**Applicable Requirements** - Final Construction Permit 11MF332 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF332

- Limits opacity to 20%
- Requires bagfilter control of ash silos
- Sets forth measures for minimizing fugitive dust emissions

Construction Permit requirement is revised from: “All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system.” To: “All process equipment shall be maintained and operated so as to minimize leakage of air contaminents to the atmosphere prior to their treatment in the pollution control system.”

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control

equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: truck loading for disposal

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

**Emission Factors** - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions.

**Monitoring Plan** - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloader on silo A dischargers directly into silo A. Therefore, there is not a separate source of emissions. The dry ash unloading on silo B discharges to a bagfilter which discharges inside the silo B building adjacent to a piperack, therefore, a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. The word “credible” as it is used in the term “credible evidence” shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence. Quarterly inspections will be performed to ensure the bagfilters and PM emission minimization measures are in place.

**Compliance Status** - The Division accepts the process was in compliance at the time the Title V application was submitted.

**P204 – Ash Handling System and Ash Haul Road Ash Haul Road for Units 1, 2 and 3 (Ash and Scrubber Sludge Hauling)**

The Unit 3 ash handling and processing system provides for transferring of ash from the Unit 3 boiler, baghouse hoppers, and ash collection locations in the scrubber building to an ash silo or the recycle ash tank for temporary storage before it is transported offsite for disposal or commercial sale. The boiler generates both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Flyash is pneumatically conveyed to the silo. Baghouses control PM emissions for the silo, day tank and dry ash unloading for commercial sale. Water and dustless unloaders control PM for the ash unloading operations for disposal. Magnesium chloride is applied to the unpaved portion of the ash haul road, as necessary, to control PM emissions.

**Applicable Requirements** - Final Construction Permit 12MF322(3) was issued for these activities. Applicable requirements are as follows.

Construction Permit 12MF322(3)

- Limits opacity to 20%

- Sets forth measures for minimizing fugitive dust emissions
  (*Note: Construction Permit Condition 3. States "Ash deposited in trucks for transport to disposal areas shall be sufficiently wet to maintain a moisture content greater than 12% and/or a control of visible emissions equal to that of an enclosed cargo box originally permitted." The Division believes requiring a specific moisture content is not practical. In addition, it is not practical to attempt to compare current visible emissions to the now removed cargo box. This condition is therefore revised as follows: "Ash deposited in trucks for transport to disposal areas shall be sufficiently moist to minimize fugitive emissions." This is consistent with minimization measures set forth in the Construction Permit 11MF332 for Units 1 & 2 ash handling.*

PSD Permit

- Requires magnesium chloride to be used on the ash haul road according to manufacturer's specifications

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
  Not applicable to fugitive emission sources: truck loading for disposal and haul roads.

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

**Emission Factors** - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions

**Monitoring Plan** - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloading baghouse is located inside a building, therefore a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. A quarterly inspection will be performed to ensure the bagfilters and PM emission minimization measures are in place.

**Compliance Status** - The Division accepts the process was in compliance at the time the Title V application was submitted.

**P205 – Staging/Landfilling**

Wet and dry waste products are hauled to the staging/landfilling area, where they are unloaded. The staged wastes are then subsequently loaded in a truck for final disposal at Trapper Mine. The staging/landfilling activities are considered to have negligible emissions.

**Applicable Requirements** - Final Construction Permit 11MF994(F) was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF994(F)

- Sets forth a Particulate Emissions Control Plan
  *(Note: The Construction Permit indicates that Mining activities are subject to the 20% opacity guideline, under Regulation No. 1. This activity is not "mining," but consists of construction (land clearing and leveling) and storage and handling of materials, which are also subject to the 20% opacity guideline. The permit language is revised to delete the reference to mining activities. The 20% is a guideline, as stated in Regulation No. 1 and its Statement of Basis and Purpose. The regulation shifted the use of opacity observations from an enforceable standard for area sources to a guideline in determining when the adequacy of applied control methods should be reviewed. U.S. EPA Method 9 readings are not required for these sources.)*

Other

The Construction Permit does not specifically limit the amount of waste processed, however, the amount is needed to calculate emissions estimates.

**Emission Factors** - Standard AP-42 equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and $PM_{10}$ emissions.

**Monitoring Plan -** A quarterly inspection will be performed to ensure PM emission minimization measures are in place.

**Compliance Status** - The Division accepts the process was in compliance at the time the Title V application was submitted.

**P206 - Soda Ash Addition System**

This system was for addition of soda ash to coal for Boiler Units #1 and #2. Due to the Consent Decree changes to the scrubber system, the soda ash addition system has been dismantled and is not longer included in this operating permit.

**P401 – Unit 1 Cooling Tower**
**P402 – Unit 2 Cooling Tower**

The cooling towers are used to dissipate waste heat from the boilers circulating water system. Pollutants expected to be emitted include PM and small quantities of chloroform produced by the introduction of chlorine in the recirculating cooling tower water to control biological growth. The cooling towers were not permitted at the time of the initial Operating Permit application submittal. The application documents for a construction permit were submitted and Initial construction permits were subsequently issued.

**Applicable Requirements** - Initial Construction Permits 98MF0141 and 96MF195 were issued for these sources. The source has demonstrated compliance under the provisions of Regulation No. 3, Part B, Section IV.H for initial approval construction permit 98MF0141 but not yet received a final approval construction permit. Under the provisions of Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit.

Construction Permits 98MF0141 and 96MF195

- Limit the design and maximum circulating water rates.
- Limit the total dissolved solids content of the water.
- Limit the drift loss and set forth schedules for retrofitting drift eliminators (at the time of Construction Permit issuance, the cooling towers equipped with older style drift eliminators. New, more efficient drift eliminators are considered to represent “BACT” for cooling towers, and the schedule was developed to implement the new style drift eliminators.) The Construction Permits require progress reports by March 31 of the following year. The Operating Permit requires reports by April 30, to be consistent with APEN reporting requirements. (*Note: Construction of the new drift eliminators is completed, therefore the schedule is not included in this operating permit.*)
- Limits PM, $PM_{10}$, and VOC emissions

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

**Emission Factors** - PM emissions are estimated using EPA factors. VOC emissions are estimated using factors from a report by Michelletti. A copy of the report is included in the Operating Permit application.

**Monitoring Plan** - Measurements of TDS will be made and recorded monthly.

**Compliance Status** - The applicant has submitted the documents needed to obtain a construction permit and permits were issued. The Division accepts the cooling towers are now in compliance.

**Miscellaneous**

**Emission Factors -** From time to time published emission factors and/or other emission estimating methods are changed based on new or improved data. A logical concern is what happens if the use of the new factors/methods in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors, equations, and/or other emission estimating methods included in the permit are considered to be fixed until changed by the permit. Obviously, emission factors dependent on the fuel sulfur content or heat content of the fuel can not be fixed and will vary with the test results. The method for determining the emissions is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, etc. and to notify the Division in writing of impacts on the permit requirements when there is a change. Upon notification, the Division will work with the permittee to address the situation. In addition, the Division will review the factors, etc. as appropriate during permit modifications and renewals.

**APEN Reporting for Insignificant Activities -** Some sources permitted under the issued Construction Permits are insignificant sources because the uncontrolled actual emissions for recent years are below APEN de minimis levels. (Note: Those sources with emissions below de minimis levels, but which are subject to an NSPS requirement are still subject to APEN reporting requirements.) These sources are listed in the Operating Permit as permitted sources, in the event emissions should increase above the de minimis level in the future.

**Accidental Release Program – 112(r)**

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plant (RMP) as specified in the Rule.

Based on the information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

**Compliance Assurance Monitoring (CAM)**

The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-controlled emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set foth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV:

None.

(The Title V application was deemed administratively complete prior to April 20, 1998.)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit MM: Tri-State, *General APEN- Form APCD-200* (Apr. 21, 2025)

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Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

# General APEN – Form APCD-200

Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN form must be completed for both new and existing sources, including APEN updates. The Permit Application/Registration Checklist (Form APCD-100) must also be completed and submitted with this APEN form, unless specifically exempted. Incomplete applications will be rejected and will require re-submittal. *Your application will be rejected if it is filled out incorrectly, is missing information, or lacks payment for applicable fees. The re-submittal will require new payment for applicable fees.*

There may be a more specific APEN for your source (e.g. boiler, mining operations, engines, etc.). A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

## Section 1 - Administrative Information

Company Name[1]: Tri-State Generation and Transmission Association, Inc.

Site Name: Craig Station

Site Location: 2101 S. Ranney
Craig CO 81626

Site Location County: Moffat

NAICS or SIC Code: 4911

Mailing Address: *(Include Zip Code)* 1100 W. 116th Avenue
Westminster, CO

Contact Person: Brian Massengale

Phone Number: 303-254-3785

Portable Source Home Base: NA

E-Mail Address[2]: brian.massengale@tristategt.org

[1] Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.
[2] Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

517882

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

## Section 2 - Requested Action

☐ **NEW permit OR newly-reported emission source** *(check one below)*

☐ STATIONARY source ☐ PORTABLE source

- OR -

☐ **MODIFICATION to existing permit** *(check each box below that applies)*

☐ Change fuel or equipment ☐ Change company name[3] ☐ Add point to existing permit

☐ Change permit limit ☐ Transfer of ownership[4] ☐ Other *(describe below)*

- OR -

☑ **APEN submittal for update only (Note blank APENs will not be accepted)**

- ADDITIONAL PERMIT ACTIONS -

☐ **Limit Hazardous Air Pollutants (HAPs) with a federally-enforceable limit on Potential To Emit (PTE)**

☐ **APEN submittal for permit exempt/grandfathered source**

**Additional Info & Notes:** Craig Station Unit 1 Boiler

[3] For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.
[4] For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.

## Section 3 - General Information

General description of equipment and purpose: Electric Generation

Manufacturer: Babcock & Wilcox Model No.: NB24157 Serial No.: NA

Company equipment Identification No. *(optional)*: B001

For *existing* sources, operation began on: 1980

For *new or reconstructed* sources, the projected start-up date is: NA

☑ Check this box if operating hours are 8,760 hours per year; if fewer, fill out the fields below:

Normal Hours of Source Operation: _____ hours/day _____ days/week _____ weeks/year

Seasonal use percentage: Dec-Feb: _____ Mar-May: _____ Jun-Aug: _____ Sep-Nov: _____

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

## Section 4 - Processing/Manufacturing Information & Material Use

☑ Check box if this information is not applicable to source or process

From what year is the *actual annual amount*? _____

| | Description | Design Process Rate *(Specify Units)* | Actual Annual Amount *(Specify Units)* | Requested Annual Permit Limit[5] *(Specify Units)* |
|---|---|---|---|---|
| **Material Consumption:** | | | | |
| | | | | |
| | | | | |
| **Finished Product(s):** | | | | |
| | | | | |
| | | | | |

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

## Section 5 - Geographical/Stack Information

| Geographical Coordinates *(Latitude/Longitude or UTM)* |
|---|
| 13T 280,410 m E 4,482,335 m N |

☐ Check box if the following information is not applicable to the source because emissions will not be emitted from a stack. If this is the case, the rest of this section may remain blank.

| Operator Stack ID No. | Discharge Height Above Ground Level *(Feet)* | Temp. *(°F)* | Flow Rate *(ACFM)* | Velocity *(ft/sec)* |
|---|---|---|---|---|
| S001 | 600 | 117 | 1,838,406 | 62 |

Indicate the direction of the stack outlet: *(check one)*

☑ Upward ☐ Downward ☐ Upward with obstructing raincap

☐ Horizontal ☐ Other *(describe)*: _____

Indicate the stack opening and size: *(check one)*

☑ Circular Interior stack diameter *(inches)*: 300

☐ Square/rectangle Interior stack width *(inches)*: _____ Interior stack depth *(inches)*: _____

☐ Other *(describe)*: _____

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

## Section 6 - Combustion Equipment & Fuel Consumption Information

☐ Check box if this information is not applicable to the source (e.g. there is no fuel-burning equipment associated with this emission source)

| Design Input Rate *(MMBTU/hr)* | Actual Annual Fuel Use *(Specify Units)* | Requested Annual Permit Limit[5] *(Specify Units)* |
|---|---|---|
| 4,318 | 956,258 tpy | 3,900,000 tpy |

From what year is the *actual annual fuel use* data? 2024

Indicate the type of fuel used[6]:

☐ Pipeline Natural Gas *(assumed fuel heating value of 1,020 BTU/SCF)*

☐ Field Natural Gas Heating value: _____ BTU/SCF

☐ Ultra Low Sulfur Diesel *(assumed fuel heating value of 138,000 BTU/gallon)*

☐ Propane *(assumed fuel heating value of 2,300 BTU/SCF)*

☑ Coal Heating value: 9,763 BTU/lb Ash content: 9.3% Sulfur content: 0.4%

☐ Other *(describe)*: _____ Heating value *(give units)*: _____

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

[6] If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

## Section 7 - Criteria Pollutant Emissions Information

Attach all emission calculations and emission factor documentation to this APEN form.

Is any emission control equipment or practice used to reduce emissions? ☑ Yes ☐ No

If yes, describe the control equipment AND state the collection and control efficiencies:

| Pollutant | Control Equipment Description | Collection Efficiency *(% of total emissions captured by control equipment)* | Control Efficiency *(% reduction of captured emissions)* |
|---|---|---|---|
| TSP (PM) | Baghouse | | 99.9 |
| $PM_{10}$ | Baghouse | | 99.9 |
| $PM_{2.5}$ | Baghouse | | 99.9 |
| $SO_x$ | Wet Scrubber | | 93.7 |
| $NO_x$ | Low NOx Burner/Overfire Air | | 45-60 |
| CO | None | | |
| VOC | None | | |
| Other: | | | |

Docusign Envelope ID: D6928A96-6020-4C46-BCC9-02DA7F27CD98

**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

From what year is the following reported *actual annual emissions* data? 2024

Use the following table to report the criteria pollutant emissions from source:
*(Use the data reported in Sections 4 and 6 to calculate these emissions.)*

| Pollutant | Uncontrolled Emission Factor *(Specify Units)* | Emission Factor Source *(AP-42, Mfg., etc.)* | Actual Annual Emissions | | Requested Annual Permit Emission Limit(s)[5] | |
|---|---|---|---|---|---|---|
| | | | Uncontrolled *(tons/year)* | Controlled[7] *(tons/year)* | Uncontrolled *(tons/year)* | Controlled *(tons/year)* |
| TSP (PM) | 0.0100 lb/MMBtu | 2024 Stack Test, AP-42 | | 93 | | NA |
| $PM_{10}$ | 0.0092 lb/MMBtu | 2024 Stack Test, AP-42 | | 86 | | NA |
| $PM_{2.5}$ | 0.0053 lb/MMBtu | 2024 Stack Test, AP-42 | | 49 | | NA |
| $SO_x$ | Measured | CEMS | | 335 | | NA |
| $NO_x$ | Measured | CEMS | | 2,176.6 | | NA |
| CO | 0.5 lb/ton | AP-42 | 239 | | | NA |
| VOC | 0.0002 lb/MMBtu | 1999 Stack Test, AP-42 | 2 | | | NA |
| Other: | | | | | | |

[5] Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.
[7] Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

## Section 8 - Non-Criteria Pollutant Emissions Information

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year? ☑ Yes ☐ No

If yes, use the following table to report the non-criteria pollutant (HAP) emissions from source:
*(Use the data reported in Sections 4 and 6 to calculate these emissions.)*

| CAS Number | Chemical Name | Overall Control Efficiency | Uncontrolled Emission Factor *(Specify Units)* | Emission Factor Source *(AP-42, Mfg., etc.)* | Uncontrolled Actual Emissions *(lbs/year)* | Controlled Actual Emissions[7] *(lbs/year)* |
|---|---|---|---|---|---|---|
| 7782505 / 7440-02-0 | Chlorine / Nickel | | 518 lb/TBtu / 1.4E-4 lb/MMBtu | 2000 Stack Test / 2010 Test | 10,168 / 2,748 | |
| 7440-47-3 / 75-09-2 | Chromium / Methylene Chloride | | 2.08 E-4 lb/MMBtu / 18.9E-6 lb/TBtu | 2010 Stack Test / EPRI | 4,083 / 371 | |
| 57-12-5 / 7664-93-9 | Cyanide / Sulfuric Acid | | 2.5 E-3 lb/ton / 7E-4 lb/MMBtu | AP-42 / 2009 Stack Test | 2,391 / 13,070 | |
| 7647-01-0 | Hydrogen Chloride | | 5.5 E-5 lb/MMBtu | 2009 Stack Test | 1,080 | |
| 7664-39-3 | Hydrogen Fluoride | | 2.07 E-4 lb/MMBtu | 2009 Stack Test | 4,063 | |
| 7439-96-5 | Manganese | | 3.67E-4 lb/MMBtu | 2010 Stack Test | 7,204 | |

[7] Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

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**Permit Number:** 96OPMF155 **AIRS ID Number:** 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

## Section 9 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct.

DocuSigned by:
Jerome Sturhahn
AFDDE2F9ABE741D...

4/21/2025

Signature of Legally Authorized Person (not a vendor or consultant) Date

Jerome H. Sturhahn Senior Vice President, General Counsel

Name (print) Title

**Check the appropriate box to request a copy of the:**

☐ Draft permit prior to issuance
☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with $242.00 to:

**Colorado Department of Public Health and Environment**
**Air Pollution Control Division**
**APCD-SS-B1**
**4300 Cherry Creek Drive South**
**Denver, CO 80246-1530**

For more information or assistance, contact:

**Small Business Assistance Program**
cdphe_apcd_sbap@state.co.us

**APCD Main Phone Number**
(303) 692-3100

Make check payable to: **Colorado Department of Public Health and Environment**

Alternatively, payment can be provided online, by credit card or electronic check, via the APCD Payment Portal.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit NN: Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)

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# *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*

## *Colorado Air Pollution Control Division*

***Revised Regional Haze Plan***
***Adopted by the Colorado Air Quality Control Commission on December 15, 2016***

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## Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

| Regional Haze Plan | Approval Date |
|---|---|
| Original | 12/21/2007 |
| First Revision | 12/19/2008 |
| Second Revision | 01/07/2011 |
| Third Revision | 11/20/2014 |
| Fourth Revision | 12/15/2016 |

# Chapter 1 Overview

## 1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to 'natural conditions' by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources. Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064, this plan is designed to meet the two requirements for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal. This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

## 1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

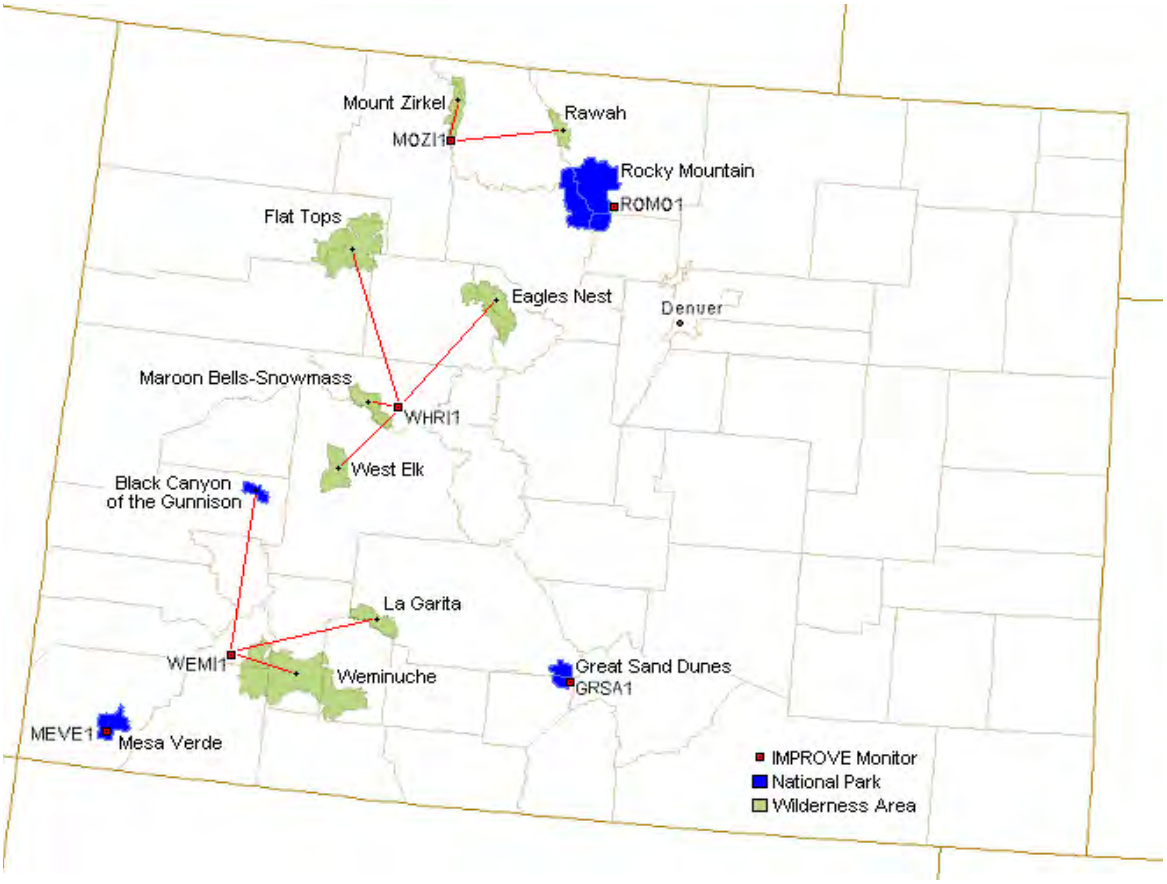
## 1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

*Black Canyon of the Gunnison National Park*
*Eagles Nest Wilderness Area*
*Flat Tops Wilderness Area*
*Great Sand Dunes National Park*
*La Garita Wilderness Area*
*Maroon Bells-Snowmass Wilderness Area*
*Mesa Verde National Park*
*Mount Zirkel Wilderness Area*
*Rawah Wilderness Area*
*Rocky Mountain National Park*
*Weminuche Wilderness Area*
*West Elk Wilderness Area*

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

**Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations**




## 1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006. As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures.

This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

## 1.5 Reasonable Progress towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

# Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

## 2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA's so called 'presumptive' emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state's conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination.

Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements. Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

## 2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

## 2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents. By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

## 2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

# Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

## 3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others. The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow. The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to "develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan." The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA's Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, "The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network." The federal agencies' monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

## 3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1, and will be met by participating in the IMPROVE network.

Colorado's monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

## 3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
    a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
    b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
    a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
    b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
    a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/). Through participation in the IMPROVE network, Colorado will partially satisfy the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.
    b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].
    a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.
        i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls
5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].
    a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see Section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.
6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].
    a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

## 3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service.

In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management. The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical. The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

**Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations**

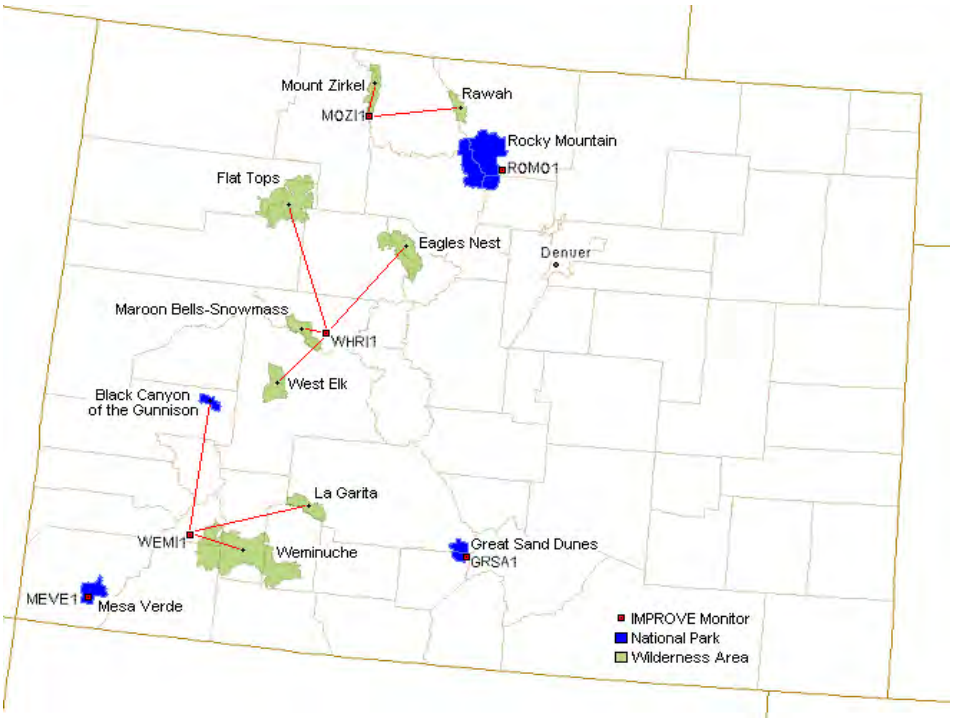



Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

**Figure 3-2 Colorado IMPROVE Monitoring Site Information**

| Mandatory Class I Federal Area | Operating Agency | IMPROVE Monitor | Elevation [ft] | Start Date |
|---|---|---|---|---|
| Great Sand Dunes National Park | NPS | GRSA1 | 8,215 | 5/4/1988 |
| Mesa Verde National Park | NPS | MEVE1 | 7,142 | 3/5/1988 |
| Mount Zirkel Wilderness | USFS | MOZI1 | 10,640 | 7/30/1994 |
| Rawah Wilderness | | | | |
| Rocky Mountain National Park | NPS | ROMO1 | 9,039 | 9/19/1990 |
| Weminuche Wilderness | USFS | WEMI1 | 9,072 | 3/2/1988 |
| Black Canyon of Gunnison NP | | | | |
| La Garita Wilderness | | | | |
| Eagles Nest Wilderness | USFS | WHRI1 | 11,214 | 7/17/2000 |
| Flat Tops Wilderness | | | | |
| Maroon Bells-Snowmass Wilderness | | | | |
| West Elk Wilderness | | | | |

## 3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network.

[2] http://vista.cira.colostate.edu/improve/

Colorado will continue to work with EPA in refining monitoring strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements. Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network. As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v). The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations.

The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

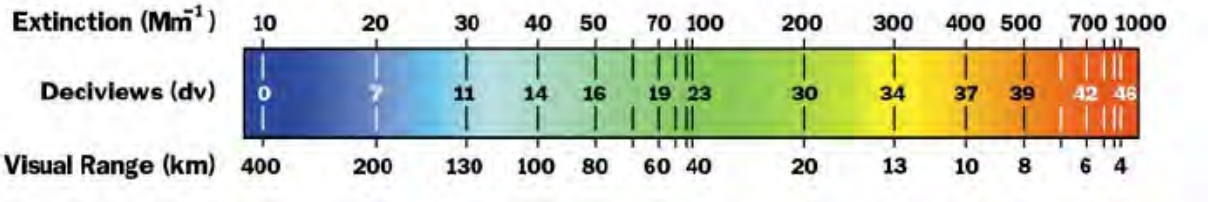
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

# Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

## 4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as $b_{ext}$) is expressed in units of inverse megameters (1/Mm or $Mm^{-1}$). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction ($Mm^{-1}$), haze index (dv) and visual range (km) are




indicated by the following scale:

## 4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

## 4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the "Haze Index", which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado's twelve Class I areas. The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

**Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)**

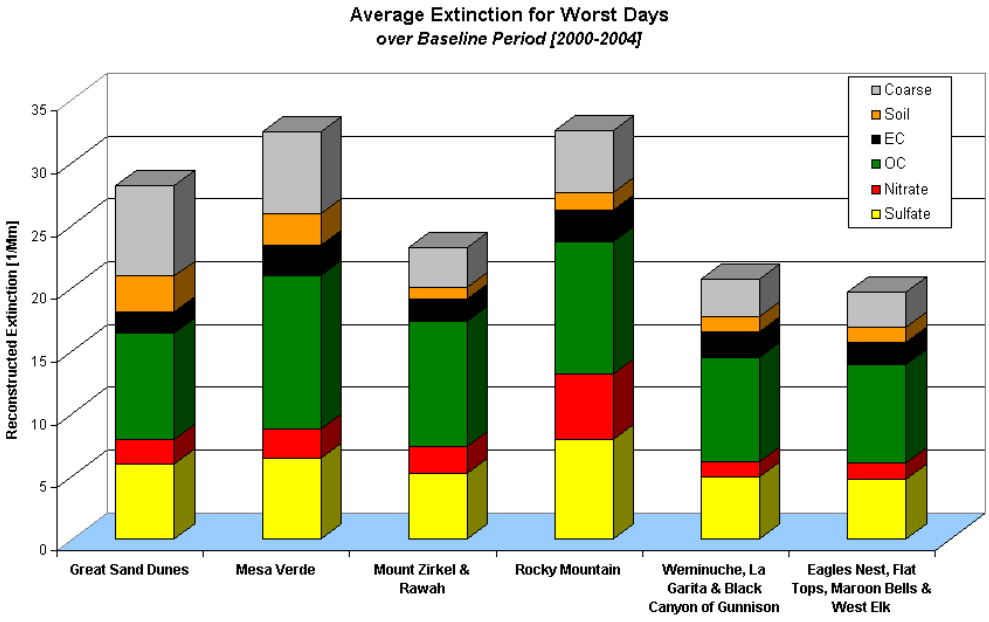
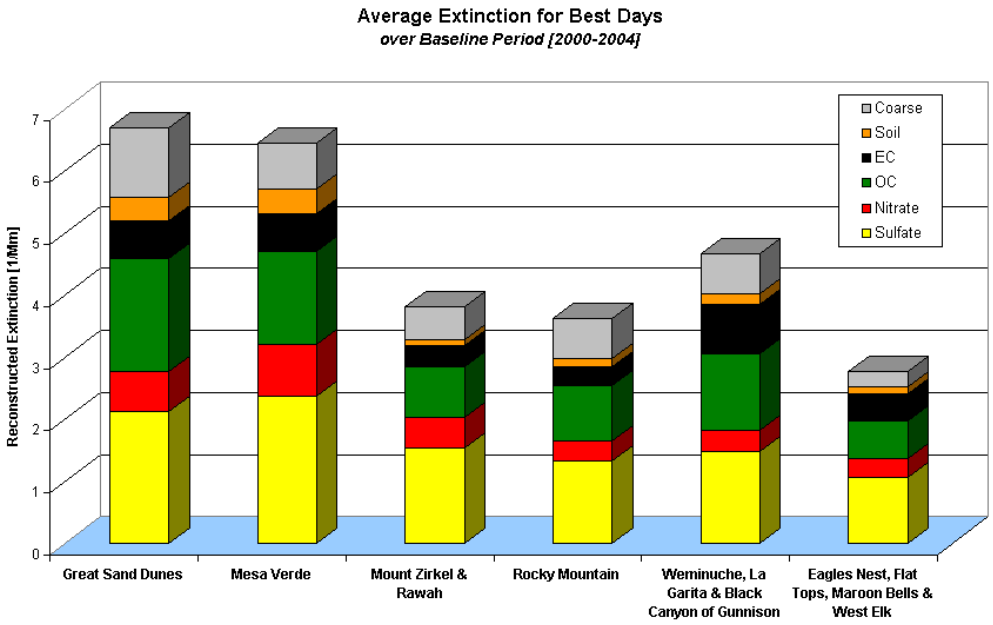


**Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)**




More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

## 4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)]. Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

**Figure 4-3: 2064 Natural Conditions Goal for Worst Days**

| Mandatory Class I Federal Areas in Colorado | 2064 Natural Conditions for 20% Worst Days [Deciview] |
|---|---|
| Great Sand Dunes National Park & Preserve | 6.66 |
| Mesa Verde National Park | 6.81 |
| Mount Zirkel & Rawah Wilderness Areas | 6.08 |
| Rocky Mountain National Park | 7.15 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 6.21 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 6.06 |

## 4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

*URP = [Baseline Condition - Natural Condition] / 60 years*

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

*2018 UPG = [URP] x [14 years]*

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions. More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado's twelve Class I areas. This calculation is consistent with EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Rule* (June 1, 2007). For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day's baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

**Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area**

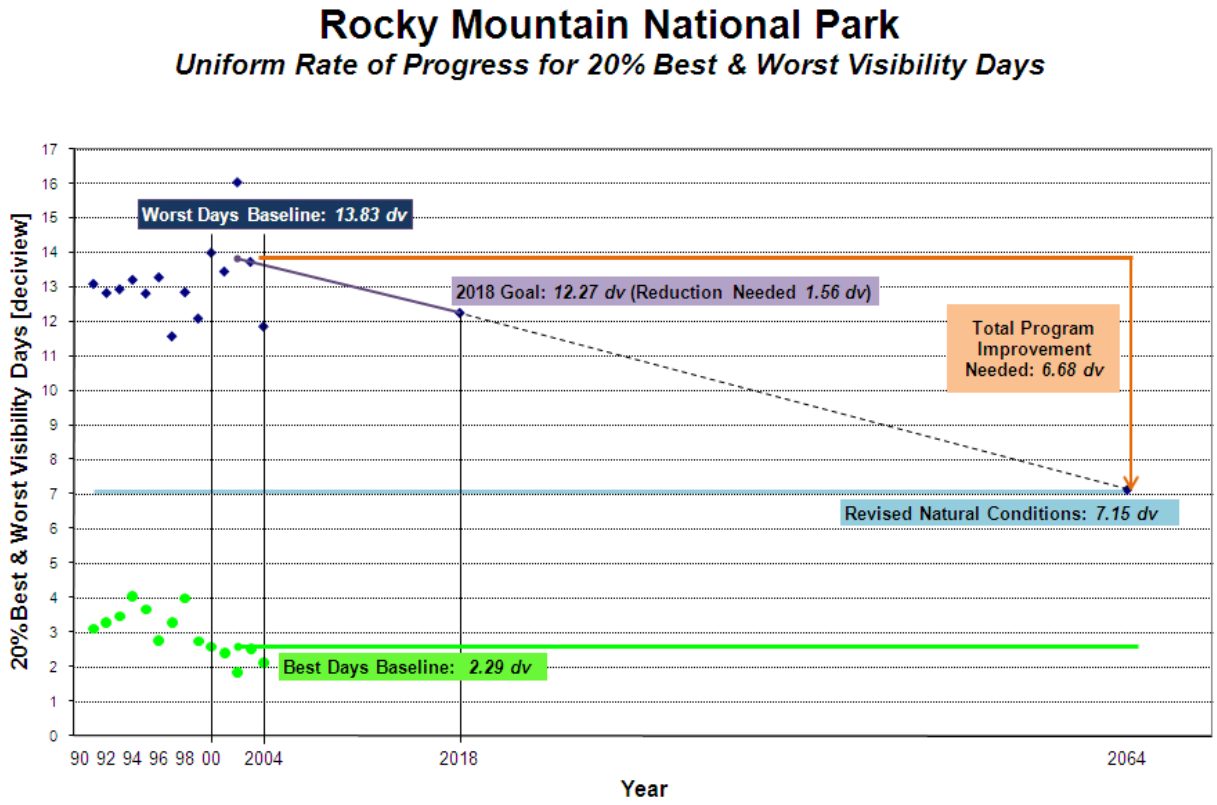
**Baseline Summary of Best & Worst Days in Haze Index Metric**

***Baseline Period (2000-2004)***

| | 20% Worst Days | | | | | 20% Best Days |
|---|---|---|---|---|---|---|
| Mandatory Class I Federal Area | Baseline Condition [Deciview] | 2018 Uniform Progress Goal [Deciview] | 2018 Goal Delta [Deciview] | 2064 Natural Conditions [deciview] | 2064 Delta (Baseline - 2064 NC) [deciview] | Best Days Baseline Condition [Deciview] |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 6.66 | 6.12 | 4.50 |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 6.81 | 6.22 | 4.32 |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 6.08 | 4.44 | 1.61 |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 7.15 | 6.68 | 2.29 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 6.21 | 4.12 | 3.11 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 6.06 | 3.55 | 0.70 |

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best day's baseline.

**Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park**



# Chapter 5 Sources of Impairment in Colorado

## 5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days. Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

## 5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

## 5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3.

Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

## 5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD. Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods.

For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The "Plan 2002(d)" and "PRP 2018(b)" phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

**Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | **Statewide SO2 Emissions** | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 97,984 | 44,062 | -55% |
| Area | 6,533 | 7,644 | 17% |
| On-Road Mobile | 4,389 | 677 | -85% |
| Off-Road Mobile | 3,015 | 754 | -75% |
| WRAP Area O&G | 118 | 11 | -91% |
| Road Dust | 4 | 6 | 34% |
| Fugitive Dust | 6 | 5 | -13% |
| Anthro Fire | 108 | 91 | -15% |
| Natural Fire | 3,335 | 3,335 | 0% |
| Biogenic | - | - | - |
| **Total:** | **115,492** | **56,585** | **-51%** |

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as 'natural' these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

**Figure 5-2 Colorado $NO_x$ Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | Statewide NOx Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 118,667 | 101,818 | -14% |
| Area | 11,729 | 16,360 | 39% |
| On-Road Mobile | 141,883 | 45,249 | -68% |
| Off-Road Mobile | 62,448 | 37,916 | -39% |
| WRAP Area O&G | 23,518 | 33,517 | 43% |
| Road Dust | 1 | 1 | 32% |
| Fugitive Dust | 16 | 14 | -13% |
| Anthro Fire | 520 | 408 | -21% |
| Natural Fire | 9,377 | 9,377 | 0% |
| Biogenic | 37,349 | 37,349 | 0% |
| **Total:** | **405,507** | **282,010** | **-30%** |

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources.

Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

**Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | **Statewide VOC Emissions** | | |
| | Plan 2002(d) | PRP 2018(b) | Net |
| | *[tons/year]* | *[tons/year]* | Change |
| Point | 91,750 | 77,312 | -16% |
| Area | 99,191 | 136,032 | 37% |
| On-Road Mobile | 100,860 | 41,489 | -59% |
| Off-Road Mobile | 38,401 | 24,684 | -36% |
| WRAP Area O&G | 27,259 | 43,639 | 60% |
| Road Dust | - | - | - |
| Fugitive Dust | - | - | - |
| Anthro Fire | 915 | 666 | -27% |
| Natural Fire | 20,404 | 20,404 | 0% |
| Biogenic | 804,777 | 804,777 | 0% |
| **Total:** | **1,183,557** | **1,149,002** | **-3%** |

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

**Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | Statewide POA Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 17 | 3 | -83% |
| Area | 8,432 | 8,738 | 4% |
| On-Road Mobile | 1,280 | 1,288 | 1% |
| Off-Road Mobile | 1,286 | 843 | -34% |
| WRAP Area O&G | - | - | - |
| Road Dust | 102 | 135 | 33% |
| Fugitive Dust | 777 | 677 | -13% |
| Anthro Fire | 850 | 621 | -27% |
| Natural Fire | 30,581 | 30,581 | 0% |
| Biogenic | - | - | - |
| **Total:** | **43,325** | **42,886** | **-1%** |

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

**Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | Statewide EC Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | - | - | - |
| Area | 1,264 | 1,325 | 5% |
| On-Road Mobile | 1,448 | 408 | -72% |
| Off-Road Mobile | 3,175 | 1,344 | -58% |
| WRAP Area O&G | - | - | - |
| Road Dust | 9 | 11 | 33% |
| Fugitive Dust | 53 | 46 | -13% |
| Anthro Fire | 92 | 74 | -20% |
| Natural Fire | 6,337 | 6,337 | 0% |
| Biogenic | - | - | - |
| **Total:** | **12,377** | **9,545** | **-23%** |

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

**Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | **Statewide Soil (fine PM) Emissions** | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 6 | 85 | 1404% |
| Area | 4,170 | 4,311 | 3% |
| On-Road Mobile | - | - | - |
| Off-Road Mobile | - | - | - |
| WRAP Area O&G | - | - | - |
| Road Dust | 1,082 | 1,435 | 33% |
| Fugitive Dust | 13,401 | 11,679 | -13% |
| Windblown Dust | 15,105 | 15,105 | 0% |
| Anthro Fire | 253 | 169 | -33% |
| Natural Fire | 1,948 | 1,948 | 0% |
| Biogenic | - | - | - |
| **Total:** | **35,964** | **34,732** | **-3%** |

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

**Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | Statewide Coarse PM Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 21,096 | 26,828 | 27% |
| Area | 1,363 | 1,388 | 2% |
| On-Road Mobile | 794 | 917 | 15% |
| Off-Road Mobile | - | - | - |
| WRAP Area O&G | - | - | - |
| Road Dust | 8,930 | 11,826 | 32% |
| Fugitive Dust | 67,642 | 67,910 | 0% |
| Windblown Dust | 135,945 | 135,945 | 0% |
| Anthro Fire | 51 | 32 | -37% |
| Natural Fire | 5,973 | 5,973 | 0% |
| Biogenic | - | - | - |
| **Total:** | **241,794** | **250,818** | **4%** |

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

**Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018**

| *Colorado Planning and Projection Emission Inventories* | | | |
|---|---|---|---|
| Source Category | Statewide Ammonia Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 453 | 571 | 26% |
| Area | 60,771 | 60,791 | 0% |
| On-Road Mobile | 4,317 | 5,894 | 37% |
| Off-Road Mobile | 43 | 60 | 38% |
| WRAP Area O&G | - | - | - |
| Road Dust | - | - | - |
| Fugitive Dust | - | - | - |
| Anthro Fire | 137 | 95 | -31% |
| Natural Fire | 1,965 | 1,965 | 0% |
| Biogenic | - | - | - |
| **Total:** | **67,686** | **69,375** | **2%** |

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

# Chapter 6 Best Available Retrofit Technology

## 6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977. Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

## 6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation Number 3, Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.

2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98$^{th}$ percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.
3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

## 6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1.

**Table 6 - 1 Results of Subject-to-BART Modeling**

| Modeled BART–Eligible Source | Division Modeling (98th percentile delta-deciview value) | Division Approved Refined Modeling from Source Operator ($98^{th}$ percentile delta-deciview value) | Contribution Threshold (deciviews) | Impact Equal to or Greater Than Contribution Threshold? |
|---|---|---|---|---|
| CEMEX - Lyons Cement Kiln & Dryer | 1.533 | | 0.5 | Yes |
| CENC (Trigen-Colorado) Units 4 & 5 | 1.255 | | 0.5 | Yes |
| Cherokee Station – Unit 4 | 1.460 | | 0.5 | Yes |
| Comanche Station – Units 1 and 2 | 0.701 | | 0.5 | Yes |
| Craig Station – Units 1 & 2 | 2.689 | | 0.5 | Yes |
| Hayden Station – Units 1 & 2 | 2.538 | | 0.5 | Yes |
| Lamar Light & Power – Unit 6 | 0.064 | | 0.5 | No |
| Martin Drake Power Plant – Units 5, 6 & 7 | 1.041 | | 0.5 | Yes |
| Pawnee Station – Unit 1 | 1.189 | | 0.5 | Yes |
| Ray D. Nixon Power Plant – Unit 1 | 0.570 | 0.481 | 0.5 | No |
| Suncor Denver Refinery | 0.239 | | 0.5 | No |
| Valmont Station – Unit 5 | 1.591 | | 0.5 | Yes |
| Notes: | | | | |
| 1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model. | | | | |
| 2. Source operator modeling results are shown only if modeling has been approved by Division. | | | | |
| 3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. | | | | |
| 4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu). | | | | |
| 5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction. | | | | |
| 6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2. | | | | |
| 7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards. | | | | |

Of the BART-eligible sources listed, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

## Table 6 - 2 BART Determinations for Colorado Sources

| Emission Unit | Assumed ** NOx Control Type | NOx Emission Limit | Assumed ** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed ** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Cemex - Lyons** Kiln | Selective Non-Catalytic Reduction System | 255.3 lbs/hr (30-day rolling average)<br><br>901.0 tons/yr (12-month rolling average) | None | 25.3 lbs/hr (12-month rolling average)<br><br>95.0 tons/yr (12-month rolling average) | Fabric Filter Baghouse *<br><br>0.275 lb/ton of dry feed<br><br>20% opacity |
| **Cemex - Lyons** Dryer | None | 13.9 tons/yr | None | 36.7 tons/yr | Fabric Filter Baghouse*<br><br>22.8 tons/yr<br><br>10% opacity |
| **CENC** Unit 4 | Low NOx Burners with Separated Over-Fire Air | 0.37 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **CENC** Unit 5 | Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System | 0.19 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **Comanche** Unit 1 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Comanche** Unit 2 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 1 | Selective Catalytic Reduction System | *** | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

## Table 6 - 2 BART Determinations for Colorado Sources

| Emission Unit | Assumed ** NOx Control Type | NOx Emission Limit | Assumed ** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed ** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Craig** Unit 2 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 1 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 2 | Selective Catalytic Reduction System | 0.07 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 5 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Dry Sorbent Injection | 0.26 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 6 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 7 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.29 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

| Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7] | | | | | |
|---|---|---|---|---|---|
| **Emission Unit** | **NOx Control Type** | **NOx Emission Limit** | **$SO_2$ Control Type** | **$SO_2$ Emission Limit** | **Particulate Control and Emission Limit** |
| **Cherokee** Unit 1 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 |
| **Cherokee** Unit 2 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |
| **Cherokee** Unit 3 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 |
| **Cherokee** Unit 4 | Natural Gas Operation 12/31/2017 | 0.12 lb/MMBtu (30-day rolling average) by 12/31/2017 | Natural Gas Operation 12/31/2017 | 7.81 tpy (rolling 12 month average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas Operation 12/31/2017 |
| **Valmont** Unit 5 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 |
| **Pawnee** Unit 1 | SCR** | 0.07 lb/MMBtu (30-day rolling average) by 12/31/2014 | Lime Spray Dryer** | 0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014 | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu |
| **Arapahoe** Unit 3 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Arapahoe** Unit 4 | Natural Gas Operation | 600 tpy (rolling 12 month average) 12/31/2014 | Natural Gas operation 12/31/2014 | 1.28 tpy (rolling 12 month average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas operation 12/31/2014 |

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the table is not a requirement.

[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.
[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.
[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

## 6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

### *6.4.1 The State's Consideration of BART Factors*

In identifying a level of control as BART, States are required by Section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,

(2) The energy and non-air quality environmental impacts of compliance,

(3) Any existing pollution control technology in use at the source,

(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. *See*, Regulation Number 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

***6.4.1.1 The costs of compliance***. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized and the state's consideration of this factor for each source is presented in detail in Appendix C.

***6.4.1.2 The energy and non-air quality environmental impacts of compliance***. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described.

***6.4.1.3 Any existing pollution control technology in use at the source***. The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" s*ee* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

***6.4.1.4 The remaining useful life of the source.*** None of Colorado's BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state's BART determinations.

***6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART.*** The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented and in Appendix C.

### *6.4.2 SIP Requirements from EPA's Regional Haze Rule*

The following section includes information addressing the SIP elements contained in EPA's Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division's source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado's BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

**Table 6 - 4 Colorado's BART Eligible Sources**

| Plant Name | Source Owner | Rating, Heat Input or Source type | Start Year | Current Status |
|---|---|---|---|---|
| **Cemex - Lyons** Kiln | Cemex | Portland Cement | <1977 | Subject-to-BART |
| **Cemex - Lyons** Dryer | Cemex | Portland Cement | <1977 | Subject-to-BART |
| **CENC** Unit 4 | Colorado Energy Nations Company (CENC) | 360 MMBtu/hr | 1975 | Subject-to-BART |
| **CENC** Unit 5 | CENC | 650 MMBtu/hr | 1979 | Subject-to-BART |
| **Cherokee** Unit 4 | Public Service Company of Colorado (PSCO) | 350 MW | 1968 | Subject-to-BART |
| **Comanche** Unit 1 | PSCO | 350 MW | 1973 | Subject-to-BART |
| **Comanche** Unit 2 | PSCO | 350 MW | 1976 | Subject-to-BART |

| Table 6 - 4 Colorado's BART Eligible Sources | | | | |
|---|---|---|---|---|
| **Plant Name** | **Source Owner** | **Rating, Heat Input or Source type** | **Start Year** | **Current Status** |
| **Craig** Unit 1 | Tri-State Generation and Transmission, Inc. | 446 MW | 1979 | Subject-to-BART |
| **Craig** Unit 2 | Tri-State | 446 MW | 1979 | Subject-to-BART |
| **Hayden** Unit 1 | PSCO | 190 MW | 1965 | Subject-to-BART |
| **Hayden** Unit 2 | PSCO | 275 MW | 1976 | Subject-to-BART |
| **Martin Drake** Unit 5 | Colorado Springs Utilities (CSU) | 55 MW | 1962 | Subject-to-BART |
| **Martin Drake** Unit 6 | CSU | 85 MW | 1968 | Subject-to-BART |
| **Martin Drake** Unit 7 | CSU | 145 MW | 1974 | Subject-to-BART |
| **Pawnee** Unit 1 | PSCO | 500 MW | 1981 | BART Alternative |
| **Valmont** Unit 5 | PSCO | 188 MW | 1964 | Subject-to-BART |
| **Denver Steam** Unit 1 | PSCO | Steam only 210 MMBtu/hr | 1972 | Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110 |
| **Denver Steam** Unit 2 | PSCO | Steam only 243 MMBtu/hr | 1974 | Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110 |
| **Holcim** Kiln | Holcim | Portland Cement | <1977 | Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions. |
| **Lamar Utilities** | City of Lamar | 25 MW | 1972 | Plant will be shut down; so will no longer be subject. |
| **Oregon Steel** | Oregon Steel | Steel Mfg. | <1977 | Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions. |
| **Ray Nixon** Unit 1 | CSU | 227 MW | 1980 | Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact) |
| **Roche** | Roche | Pharmaceutical Mfg. | <1977 | Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO |
| **Suncor/Valero** | Suncor | Refinery | <1977 | Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO |

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation Number 3, Part F, Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation Number 3, Part F, Section VII.

### *6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source*

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,

(2) The energy and non-air quality environmental impacts of compliance,

(3) Any existing pollution control technology in use at the source,

(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations.

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[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, and Valmont Unit 5.

Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*, Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows. For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis. The cost criteria presented is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13]

[12] *See* 70 Fed. Reg. at 39170 and 39137.

[13] Air Quality Control Commission Regulation Number 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16]

The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area. Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

[15] *See, e.g.*, Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation Number 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

### *6.4.3.1 BART Determination for CEMEX's Lyons Cement Plant*

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen. Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98$^{th}$ percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98$^{th}$ percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

**SO2 BART Determination for Cemex Lyons - Kiln**

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

| Cemex Lyons -Kiln | | | | |
|---|---|---|---|---|
| SO2 Control Technology | Estimated Control Efficiency | Annual Controlled Hourly SO2 Emissions (lbs/hr) | Annual Controlled SO2 Emissions (tpy) | Annual Controlled SO2 Emissions (lb/ton of Clinker) |
| Baseline SO2 Emissions | | 25.3 | 95.0 | 0.40 |
| Lime Addition to Kiln Feed | 25% | 18.9 | 71.3 | 0.30 |
| Fuel Substitution (coal with TDF) | 40% | 15.2 | 57.0 | 0.24 |
| Dry Sorbent Injection | 50% | 12.6 | 47.5 | 0.20 |
| Wet Lime Scrubbing (Tailpipe scrubber) | 90% | 2.5 | 9.5 | 0.04 |

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See*, Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. CEMEX's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| SO2 Control Technology | SO2 Emission Reduction (tons/yr) | Annualized Cost ($/yr) | Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
| Baseline SO2 Emissions | - | | | |
| Lime Addition to Kiln Feed | 23.8 | $3,640,178 | $153,271 | |
| Fuel Substitution (coal supplemented with TDF) | 38.0 | $172,179 | $4,531 | $243,368 |
| Dry Sorbent Injection | 47.5 | Not provided | - | |
| Wet Lime Scrubbing (Tailpipe scrubber) | 85.5 | $2,529,018 | $29,579 | $49,618 |

The following table lists the projected visibility improvements for SO2 controls:

| Cemex Lyons - Kiln | | |
|---|---|---|
| SO2 Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (Δdv) |
| Maximum (24-hr max) | 0.760 | |
| Baseline (95 tpy)* | 0.731 | - |
| Lime Addition to Kiln Feed (71.3 tpy)* | 0.727 | 0.033 |
| Fuel Substitution (57 tpy)* | 0.725 | 0.034 |
| Dry Sorbent Injection (47.5 tpy)* | 0.725 | 0.036 |
| Wet Lime Scrubbing (9.5 tpy)* | 0.720 | 0.040 |

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

### SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

### Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/$PM_{10}$. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

### NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| NOx Control Technology | Estimated Control Efficiency | Annual Controlled Hourly NOx Emissions (lbs/hr) | Annual Controlled NOx Emissions (tpy) | Annual Controlled NOx Emissions (lb/ton of Clinker) |
| Baseline NOx Emissions | - | 464.3 | 1,747.1 | 7.39 |
| Water Injection | 7.0% | 431.8 | 1,624.8 | 6.87 |
| Coal w/TDF | 10.0% | 417.8 | 1,572.3 | 6.65 |
| Indirect Firing with LNB | 20.0% | 371.4 | 1,397.6 | 5.91 |
| SNCR (30-day rolling) | 45.0% | 255.3 | 960.9 | 4.06 |
| SNCR (12-month rolling) | 48.4% | 239.4 | 901.0 | 3.81 |
| SNCR w/LNB | 55% | 208.9 | 786.2 | 3.33 |

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. CEMEX's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| NOx Control Technology | NOx Emission Reduction | Annualized Cost | Cost Effectiveness | Incremental Cost Effectiveness |
| | (tons/yr) | ($/yr) | ($/ton) | ($/ton) |
| Baseline NOx Emissions | - | | | |
| Water Injection | 122.3 | $43,598 | $356 | - |
| Coal w/TDF | 174.7 | $172,179 | $986 | $2,453 |
| Indirect Firing with LNB | 349.4 | $710,750 | $2,034 | $3,083 |
| SNCR (45.0% control) | 786.2 | $1,636,636 | $2,082 | $2,120 |
| SNCR (48.4% control) | 846.1 | $1,636,636 | $1,934 | $1,864 |
| SNCR w/LNB (55.0% control w/uncertainty) | 960.9 | $1,686,395 | $1,755 | $434 |

The following table lists the projected visibility improvements for NOx controls for the kiln:

| Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (from 24-hr Max) (Δdv) |
|---|---|---|
| 24-hr Maximum (≈ 656.9 lbs/hr)) | 0.760 | |
| Revised Baseline ( ≈ 464.3 lbs/hr)* | 0.572 | 0.188 |
| Original Baseline (≈ 446.8 lbs/hr)* | 0.555 | 0.205 |
| Water Injection (≈ 431.8 lbs/hr)* | 0.540 | 0.220 |
| Firing TDF (≈417.9 lbs/hr)* | 0.526 | 0.234 |
| Indirect Firing with LNB (≈ 371.4 lbs/hr)* | 0.481 | 0.279 |
| Original BART Limit – SNCR (≈ 268.0 lbs/hr) | 0.380 | 0.380 |
| Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)** | 0.368 | 0.392 |
| Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)** | 0.352 | 0.408 |
| SNCR w/LNB (≈208.9 lbs/hr)** | 0.322 | 0.438 |

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500$^{o}$F) is significantly higher at the exit than a more typical preheater precalciner kiln (650$^{o}$F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

**NOx BART Determination for Cemex Lyons - Dryer**

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

### *6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)*

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98$^{th}$ percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009, as well as additional information upon the Division's request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

**SO2 BART Determination for CENC - Boilers 4 and 5**

Dry sorbent injection (DSI) and $SO_2$ emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| CENC Boiler 4 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| $SO_2$ Emissions Management | 1.0 | $44,299 | $43,690 |
| DSI – Trona | 468.0 | $1,766,000 | $3,774 |

| CENC Boiler 5 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| $SO_2$ Emissions Management | 0.8 | $65,882 | $78,095 |
| DSI – Trona | 844.0 | $2,094,000 | $2,482 |

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

| SO2 Control Method | CENC - Boiler 4 | | CENC - Boiler 5 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.90 | | 0.98 | |
| DSI – Trona (annual avg.) | 0.26 | 0.08 | 0.29 | 0.13 |

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)

CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

**Particulate Matter BART Determination for CENC - Boilers 4 and 5**

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/$PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for CENC - Boilers 4 and 5**

Low NOx burners (LNB), LNB plus separated overfired air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| CENC Boiler 4 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | 0 | $0 |
| LNB | 59.9 | $193,433 | $3,227 |
| SNCR | 179.8 | $694,046 | $3,860 |
| LNB+SOFA | 209.8 | $678,305 | $3,234 |
| LNB+SOFA + SNCR | 368.0 | $1,372,351 | $3,729 |
| SCR | 515.4 | $4,201,038 | $8,150 |

| CENC Boiler 5 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 48.4 | $249,858 | $5,166 |
| LNB+SOFA | 127.3 | $815,829 | $6,383 |
| SNCR | 207.3 | $923,996 | $4,458 |
| LNB+SOFA + SNCR | 353.7 | $1,739,825 | $4,918 |
| SCR | 550.0 | $6,469,610 | $11,764 |

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | CENC - Boiler 4 | | CENC - Boiler 5 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx l Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.67 | | 0.66 | |
| LNB (annual avg.) | 0.45 | 0.05 | 0.30 | 0.17 |
| SNCR (annual avg.) | 0.35 | 0.07 | 0.24 | 0.21 |
| LNB + SOFA (annual avg.) | 0.32 | 0.08 | 0.24 | 0.21 |
| LNB + SOFA + SNCR (annual avg.) | 0.19 | 0.12 | 0.17 | 0.26 |
| SCR | 0.07 | 0.18 | 0.07 | 0.31 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed in Section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in Section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

### *6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2*

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

**SO2 BART Determination for Comanche - Units 1 and 2**

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional $SO_2$ removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve $SO_2$ removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.

- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Comanche – Unit 1 | | Comanche – Unit 2 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.75 | | 0.74 | |
| Semi-Dry FGD (LSD) (annual avg.) | 0.12 | 0.35 | 0.12 | 0.33 |
| Semi-Dry FGD (LSD) (annual avg.) | 0.08 | 0.37 | 0.08 | 0.36 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

**Particulate Matter BART Determination for Comanche - Units 1 and 2**

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for Comanche - Units 1 and 2**

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Comanche Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 445.6 | $1,624,100 | $3,644 |
| SCR | 770.4 | $12,265,014 | $15,290 |

| Comanche Unit 2 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SCR | 1,480 | $14,650,885 | $9,900 |

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Comanche – Unit 1 | | Comanche – Unit 2 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (1-yr) using new LNBs | 0.20 | | 0.20 | |
| SNCR (annual avg.) | 0.10 | 0.11 | Not Feasible | - |
| SCR (annual avg.) | 0.07 | 0.14 | 0.07 | 0.17 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

| | |
|---|---|
| Comanche Unit 1: | 0.20 lb/MMBtu (30-day rolling average) |
| | 0.15 lb/MMBtu (combined annual average for units 1 & 2) |
| Comanche Unit 2: | 0.20 lb/MMBtu (30-day rolling average) |
| | 0.15 lb/MMBtu (combined annual average for units 1 & 2) |

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

#### *6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility*

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 BART Determination for Craig - Units 1 and 2**

*Wet FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* Tri-State determined that installation of perforated trays, as described, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
    1. Dibasic Acid (DBA) has not been tested at the very low inlet $SO_2$ concentrations seen at Craig Units 1 and 2.
    2. DBA could cause changes in sulfite oxidation with impacts on $SO_2$ removal and solids settling and dewatering characteristics.
    3. Installation of the perforated plate tray accomplished the same objective of increased $SO_2$ removal.
- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
    1. Two vertical ball mills were installed for additional limestone processing capability for increased $SO_2$ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high $SO_2$ removal rates.
    2. Forced oxidation within the $SO_2$ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
    3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased $SO_2$ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling $SO_2$ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.17 | | 0.16 | |
| Wet FGD | 0.11 | 0.03 | 0.11 | 0.03 |
| Wet FGD | 0.07 | 0.05 | 0.07 | 0.05 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

**Particulate Matter BART Determination for Craig - Units 1 and 2**

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

**NOx BART Determination for Craig - Units 1 and 2**

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Craig Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $3,797,000 | $4,877 |
| SCR | 4,048 | $25,036,709 | $6,184 |

| Craig Unit 2 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 806 | $3,797,000 | $4,712 |
| SCR | 3,975 | $25,036,709 | $6,298 |

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.35 | | 0.35 | |
| SNCR | 0.24 | 0.31 | 0.23 | 0.31 |
| SCR | 0.07 | 1.01 | 0.08 | 0.94 |

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements.

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1.

This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station –related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the hearing 2014 record. In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

**Scenario 1 (Close by December 31, 2025):** The first table assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table, an assumed amortization period of eight years of operation[18] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[19].

[18] Operation period begins calendar year 2018 (December 31, 2017).
[19] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

| Craig Unit 1 - $NO_x$ Cost Comparisons (assuming four years, four months of operation) | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $6,172,522 | $7,928 |
| SCR | 4,048 | $64,106,699 | $15,835 |

| Craig Unit 1 - $NO_x$ Cost Comparisons (assuming eight years of operation) | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $4,755,842 | $6,109 |
| SCR | 4,048 | $41,476,535 | $10,245 |

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

Or;

**Scenario 2:** A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023.

In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, including substantial cost information for NOx controls, can be found in Appendix C.

### *6.4.3.5 BART Determination for Public Service Company's Hayden Station*

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

**SO2 BART Determination for Hayden - Units 1 and 2**

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional $SO_2$ removal in the dry scrubbing systems present at Hayden Station.

- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve $SO_2$ removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Hayden Unit 1 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Semi-Dry FGD Upgrade – Additional Equipment and Maintenance | 61 | $141,150 | $2,317 |
| Additional Scrubber Module | 488 | $4,142,538 | $8,490 |

| Hayden Unit 2 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Semi-Dry FGD Upgrade – Additional Equipment and Maintenance | 39 | $141,150 | $3,626 |
| Additional Scrubber Module | 589 | $4,808,896 | $8,164 |

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Hayden – Unit 1 | | Hayden – Unit 2 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.34 | | 0.40 | |
| Existing Semi-Dry FGD (LSD) (annual avg.) | 0.16 | 0.09 | 0.16 | 0.18 |
| Semi-Dry FGD Upgrade (annual avg.) | 0.13 | 0.10 | 0.13 | 0.21 |
| Additional Scrubber Module (annual avg.) | 0.07 | 0.14 | 0.07 | 0.26 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

**Particulate Matter BART Determination for Hayden - Units 1 and 2**

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for Hayden - Units 1 and 2**

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Hayden Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 1,391 | $572,010 | $411 |
| SNCR | 1,391 | $1,353,500 | $973 |
| SCR | 3,120 | $10,560,612 | $3,385 |

| Hayden Unit 2 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 1,303 | $992,729 | $762 |
| SNCR | 1,610 | $1,893,258 | $1,176 |
| SCR | 3,032 | $12,321,491 | $4,064 |

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Hayden – Unit 1 | | Hayden – Unit 2 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.61 | | 0.37 | |
| LNB (annual avg.) | 0.26 | 0.69 | 0.21 | 0.40 |
| SNCR (annual avg.) | 0.26 | 0.69 | 0.18 | 0.48 |
| SCR (annual avg.) | 0.07 | 1.12 | 0.06 | 0.85 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

#### *6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant*

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98$^{th}$ percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

**SO2 BART Determination for Martin Drake - Units 5, 6 and 7**

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts.

Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Drake Unit 5 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 762 | $1,340,663 | $1,760 |

| Drake Unit 6 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 1,671 | $2,910,287 | $1,741 |
| Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average) | 2,284 | $6,186,854 | $2,709 |
| Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average) | 2,368 | $6,647,835 | $2,808 |
| Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average) | 2,507 | $7,452,788 | $2,973 |

| Drake Unit 7 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 2,657 | $3,723,826 | $1,405 |
| Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average) | 3,632 | $8,216,863 | $2,263 |
| Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average) | 3,764 | $8,829,321 | $2,345 |
| Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average) | 3,986 | $9,898,382 | $2,483 |

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Drake – Unit 5 | | Drake – Unit 6 | | Drake – Unit 7 | |
|---|---|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.94 | | 1.00 | | 0.99 | |
| DSI (annual avg.) | 0.25 | 0.12 | 0.33 | 0.18 | 0.33 | 0.29 |
| Dry FGD (LSD) (annual avg.) | Not feasible | | 0.12 | 0.24 | 0.12 | 0.39 |
| Dry FGD (LSD) (annual avg.) | Not feasible | | 0.07 | 0.26 | 0.07 | 0.41 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

**Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7**

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for PM/$PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for Martin Drake - Units 5, 6 and 7**

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Drake Unit 5 - $NO_x$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfired air (OFA) | 154 | $141,844 | $923 |
| Ultra-low NOx burners (ULNBs) | 200 | $147,000 | $736 |
| ULNBs + OFA | 215 | $288,844 | $1,342 |
| Selective Non-Catalytic Reduction (SNCR) | 231 | $1,011,324 | $4,387 |
| ULNB/SCR layered approach | 626 | $4,467,000 | $7,133 |
| Selective Catalytic Reduction (SCR) | 626 | $4,580,000 | $7,314 |

| Drake Unit 6 - NOx Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfired air (OFA) | 283 | $104,951 | $371 |
| Selective Non-Catalytic Reduction (SNCR) | 424 | $1,208,302 | $2,851 |
| Ultra-low NOx burners (ULNBs) | 452 | $232,800 | $515 |
| ULNBs + OFA | 509 | $337,751 | $664 |
| ULNB/SCR layered approach | 1,175 | $6,182,800 | $5,260 |
| Selective Catalytic Reduction (SCR) | 1,175 | $6,340,000 | $5,395 |

| Drake Unit 7 - NOx Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfired air (OFA) | 416 | $75,217 | $181 |
| Ultra-low NOx burners (ULNBs) | 583 | $386,000 | $662 |
| Selective Non-Catalytic Reduction (SNCR) | 624 | $2,018,575 | $3,233 |
| ULNBs + OFA | 749 | $461,217 | $616 |
| ULNB/SCR layered approach | 1,709 | $8,196,000 | $4,797 |
| Selective Catalytic Reduction (SCR) | 1,709 | $8,510,000 | $4,981 |

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Drake – Unit 5 | | Drake – Unit 6 | | Drake – Unit 7 | |
|---|---|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.62 | | 0.83 | | 0.71 | |
| OFA (annual avg.) | 0.30 | 0.07 | 0.33 | 0.18 | 0.31 | 0.22 |
| ULNB (annual avg.) | 0.28 | 0.08 | 0.28 | 0.193 | 0.28 | 0.24 |
| ULNB + OFA (annual avg.) | 0.27 | 0.08 | 0.27 | 0.20 | 0.25 | 0.26 |
| SNCR (annual avg.) | 0.27 | 0.08 | 0.29 | 0.19 | 0.28 | 0.24 |
| ULNB + SCR | 0.07 | 0.12 | 0.07 | 0.27 | 0.07 | 0.37 |
| SCR (annual avg.) | 0.07 | 0.12 | 0.07 | 0.27 | 0.07 | 0.37 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described (*e.g.* less than 0.50 Δdv). For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv.

Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected

limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6. For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7. A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 & 7 can be found in Appendix C.

### *6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative which includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3*

**Background**

Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with Section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” ( § 40-3.2-201 C.R.S., *et. seq.*). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed.

**Table 6-5: Actions and Dates under the PSCo Alternative**

| Facility | Unit | Action or Control | Effective Date |
|---|---|---|---|
| Arapahoe | Unit 3 | Shutdown | 12/31/2013 |
| | Unit 4 | Operation on Natural Gas only (peaking unit) | 12/31/2014 |
| Cherokee | Unit 1 | Shutdown | No later than 7/1/2012 |
| | Unit 2 | Shutdown | 12/31/2011 |
| | Unit 3 | Shutdown | No later than 12/31/2016 |
| | Unit 4 | Operation on Natural Gas only | 12/31/2017 |
| Valmont | | Shutdown | 12/31/2017 |
| Pawnee | | SCR & LSD | 12/31/2014 |

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a "peaking" unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state's alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state's analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado's alternative program was designed to meet a requirement other than BART; namely, Colorado's HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado's Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S. PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART.

This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id.* at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not necessary to assure that the alternative program will result in greater reasonable progress than BART.").

The PSCo BART Alternative includes only EGUs and, based on EPA's Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id.* The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU's of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state's analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

**Analysis under 40 CFR Part 51, § 308(e)**

*(2)(i)(A) A list of all Bart-eligible sources within the State.*

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

*(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.*

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with Section 302(c) or section 308(e)(1), or otherwise be addressed under Section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

**Table 6-6: Sources Included Within the PSCo Alternative**

| Facility | Unit | Action or Control |
|---|---|---|
| Arapahoe | Unit 3 | Shutdown |
| | Unit 4 | Operation on natural gas only |
| Cherokee | Unit 1 | Shutdown |
| | Unit 2 | Shutdown |
| | Unit 3 | Shutdown |
| | Unit 4 (BART-eligible) | Operation on natural gas only |
| | New nat. gas-fired EGU | BACT where netting does not apply |
| Valmont | (BART-eligible) | Shutdown |
| Pawnee | (BART-eligible) | SCR & LSD |

*(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[20] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

[20] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

*(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.*

The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

*(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.*

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

*(2)(ii) [Reserved]*

*(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.*

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets".

The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation Number 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation Number 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

*(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.*

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

*(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.*

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

*(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap*:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Regulation Number 3, Part F.

*(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:*

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

*(3)(i) Visibility does not decline in any Class I area, and*

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

*(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.*

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.
b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.
c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.
d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control SO2 emissions and SCR to control NOx emissions in 2014.

*(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs*

Colorado is not participating in the CAIR program.

*(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.*

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

*(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).*

No Colorado BART sources have applied for an exemption from BART.

**Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration**

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative.

EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.*, 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule."). As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe.

For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe Unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

**Table 6-7: SO2 Reductions beyond Presumptive BART for PSCo Alternative**

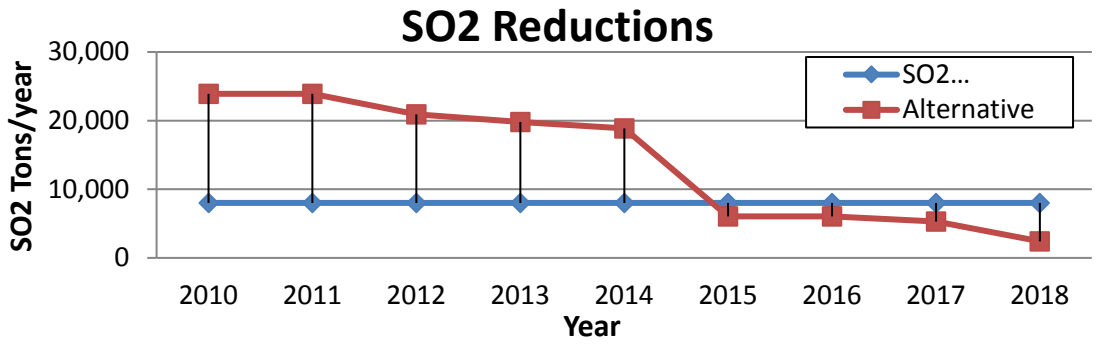
| Facility | MMBtu Average 2006 to 2008 | SO2 TPY Average 2006 to 2008 | SO2 TPY at 0.15 lb/MMBtu Presumptive | SO2 TPY under PSCo Alternative in 2018 | % Reduction Beyond Presumptive BART |
|---|---|---|---|---|---|
| Arapahoe | | | | | |
| Unit 3 | 4,380,121 | 924.97 | 328.51 | 0.00 | 100.00% |
| Unit 4 | 8,545,791 | 1,764.70 | 640.93 | 1.28[21] | 99.8% |
| Cherokee | | | | | |
| Unit 1 | 8,311,352 | 2,220.80 | 623.35 | 0.00 | 100.00% |
| Unit 2 | 5,586,021 | 1,888.37 | 418.95 | 0.00 | 100.00% |
| Unit 3 | 8,159,889 | 743.00 | 611.99 | 0.00 | 100.00% |
| Unit 4 | 26,047,648 | 2,135.43 | 1,953.57 | 7.81 | 99.6 % |
| Valmont | 13,722,507 | 758.47 | 1,029.19 | 0.00 | 100.00% |
| Pawnee | 40,093,753 | 13,472.07 | 3,007.03 | 2,405.63 | 20.00% |
| Total | 114,847,083 | 23,908 | 8,614 | 2,415 | 71.97% |

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

[21] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

**Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative**




A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

**Table 6-8: NOx Reductions beyond Presumptive BART for PSCo Alternative**

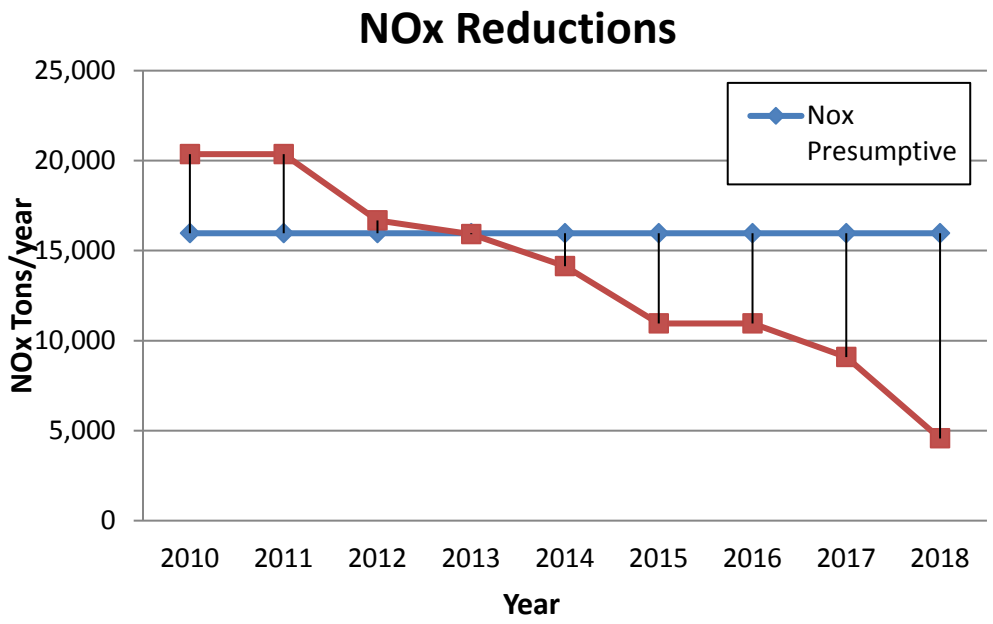
| Facility | MMBtu Average 2006 to 2008 | NOx TPY Average 2006 to 2008 | NOx lb/MMBtu Standard | TPY NOx at Standard | TPY NOx Under PSCo Alternative in 2018 | % Reduction Beyond Presumptive BART |
|---|---|---|---|---|---|---|
| Arapahoe | | | | | | |
| Unit 3 | 4,380,121 | 1,770.47 | 0.23 | 503.71 | 0.00 | 100.00% |
| Unit 4 | 8,545,791 | 1,147.67 | 0.23 | 982.77 | 900.00[22] | 8.42% |
| Cherokee | | | | | | |
| Unit 1 | 8,311,352 | 1,556.23 | 0.39 | 1,620.71 | 0.00 | 100.00% |
| Unit 2 | 5,586,021 | 2,895.20 | 0.39 | 1,089.27 | 0.00 | 100.00% |
| Unit 3 | 8,159,889 | 1,865.50 | 0.39 | 1,591.18 | 0.00 | 100.00% |
| Unit 4 | 26,047,648 | 4,274.00 | 0.28 | 3,646.67 | 2,062.86[23] | 43.43% |
| Valmont | 13,722,507 | 2,313.73 | 0.28 | 1,921.15 | 0.00 | 100.00% |
| Pawnee | 40,093,753 | 4,537.73 | 0.23 | 4,610.78 | 1,403.28 | 69.57% |
| Total | 114,847,083 | 20,361 | | 15,966 | 4,366 | 72.65% |

[22] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[23] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

**Figure 6-2: NOx Reductions beyond Presumptive BART for PSCo Alternative**




The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

**Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative**

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv. See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm NH3 slip and 54% reduction with a 10ppm NH4 slip.[24] Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[25]

[24] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[25] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

**Table 6-9: NOx reductions beyond state criteria for PSCo Alternative**

| Facility | SCR $/ton | SNCR $/ton | SNCR TPY at 50%[26] | PSCo Alternative TPY | % Reduction from SNCR at 50% Control |
|---|---|---|---|---|---|
| Arapahoe | | | | | |
| Unit 3 | | | 885.23 | 0 | 100.00% |
| Unit 4 | | | 573.83 | 900[27] | -56.84% |
| Cherokee | | | | | |
| Unit 1 | N/A | $8,737 | 778.12 | 0 | 100.00% |
| Unit 2 | N/A | $3,963 | 1,447.60 | 0 | 100.00% |
| Unit 3 | $10,134 | $3,485 | 932.75 | 0 | 100.00% |
| Unit 4 | $6,252 | $2,625 | 2,137.00 | 2,062[28] | 3.47% |
| Valmont | $8,647 | $3,328 | 1,156.87 | 0 | 100.00% |
| Pawnee | $4,371 | $3,082 | 2,268.87 | 1,403 | 38.15% |
| Total | | | 10,180 | 4,366 | 57.11% |

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[29]

[26] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[27] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation.

[28] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for "netting" or "offsets".

[29] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the

The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

**Table 6-10: SO2 Reductions beyond Source-By-Source BART for PSCo Alternative**

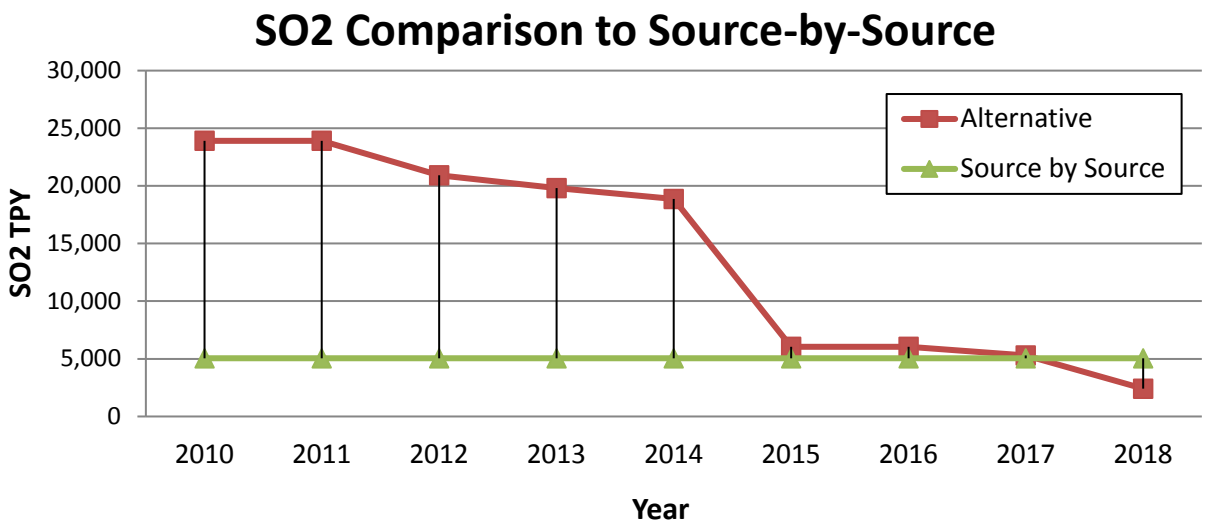
| Facility | SO2 TPY from AP-42 | Source-by-Source | SO2 TPY from PSCo Alternative | % Reduction Beyond Source-by-Source |
|---|---|---|---|---|
| Arapahoe | | | | |
| Unit 3 | 1,076.53 | 53.82 | 0.00 | 100.00% |
| Unit 4 | 2,322.21 | 1.28 | 1.28 | 0.00% |
| Cherokee | | | | |
| Unit 1 | 2,803.67 | 140.18 | 0.00 | 100.00% |
| Unit 2 | 2,662.17 | 133.10 | 0.00 | 100.00% |
| Unit 3 | 3,438.79 | 171.93 | 0.00 | 100.00% |
| Unit 4 | 9,779.27 | 1,953.57[30] | 7.81 | 99.6% |
| Valmont | 3,822.73 | 191.13 | 0.00 | 100.00% |
| Pawnee | 8,342.36 | 2,405.62[31] | 2,405.63 | 0.00% |
| Total | 34,248 | 5,051 | 2,415 | 52.19% |

other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

[30] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[31] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

**Figure 6-3: SO2 Reductions beyond Source-By-Source BART for PSCo Alternative**



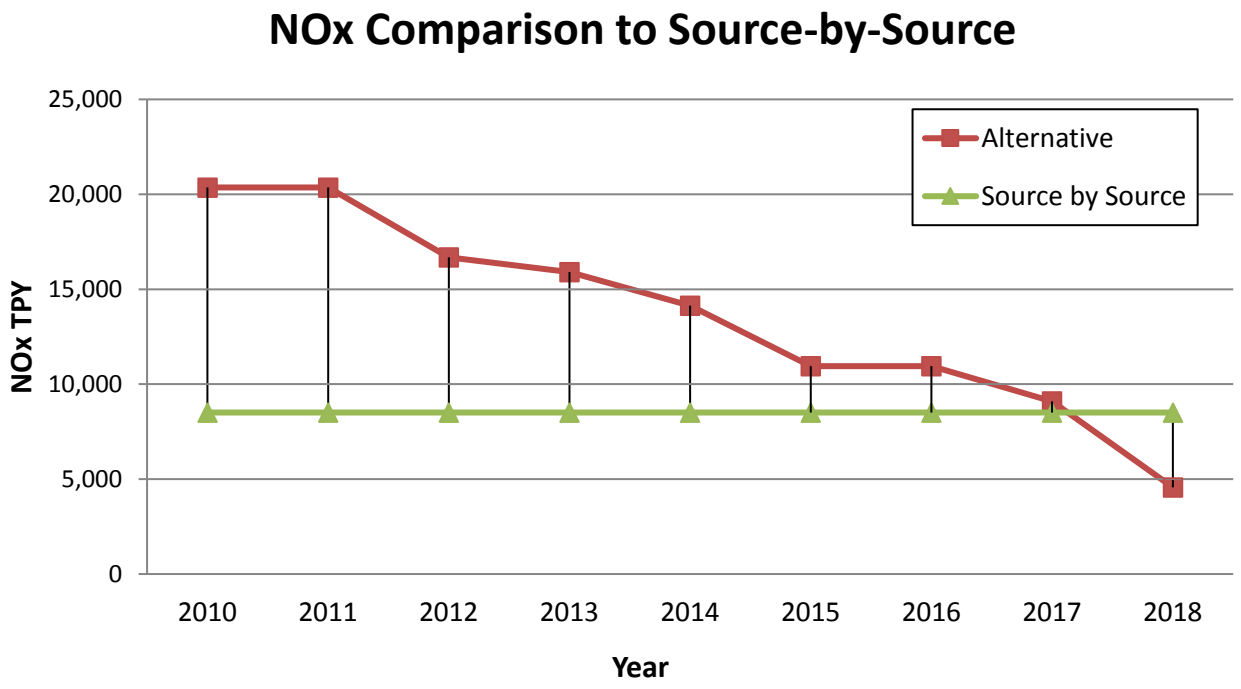

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[32] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

[32] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

**Table 6-11: NOx Reductions beyond Source-By-Source BART for PSCo Alternative**

| Facility | NOx TPY from AP-42 | Source-by-Source | NOx TPY from PSCo Alternative | % Reduction Beyond Source-by-Source |
|---|---|---|---|---|
| Arapahoe | | | | |
| Unit 3 | 2,149.15 | 214.91 | 0.00 | 100.00% |
| Unit 4 | 4,636.00 | 600 | 900.00[33] | -50.00% |
| Cherokee | | | | |
| Unit 1 | 3,596.54 | 359.65 | 0.00 | 100.00% |
| Unit 2 | 3,415.03 | 341.50 | 0.00 | 100.00% |
| Unit 3 | 4,411.28 | 441.12 | 0.00 | 100.00% |
| Unit 4 | 7,878.04 | 2,735.00[34] | 2,062.86[35] | 24.58% |
| Valmont | 2,061.04 | 206.10 | 0.00 | 100.00% |
| Pawnee | 7,945.11 | 3,608.43 | 1,403.28 | 61.11% |
| Total | 36,092 | 8,507 | 4,366 | 48.67% |

**Figure 6-4: NOx Reductions beyond Source-By-Source BART for PSCo Alternative**




[33] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[34] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[35] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

## Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

### Table 6-12: PSCo Alternative Emissions Limits[36,37,38]

| Unit | NOx Control Type | NOx Emission Limit | SO2 Control Type | SO2 Emission Limit | Particulate Type And Limit |
|---|---|---|---|---|---|
| **Cherokee** Unit 1 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 |
| **Cherokee** Unit 2 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |
| **Cherokee** Unit 3 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 |
| **Cherokee** Unit 4 | Natural Gas Operation | 0.12 lb/MMBtu (30-day rolling average) by 12/31/2017 | Natural Gas Operation 12/31/2017 | 7.81 tpy (12 month rolling average) | Fabric Filter Baghouse* 0.03 lbs/MMBtu<br><br>Natural Gas Operation 12/31/2017 |
| **Valmont** Unit 5 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 |
| **Pawnee** Unit 1 | SCR** | 0.07 lb/MMBtu (30-day rolling average) by 12/31/2014 | Lime Spray Dryer** | 0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014 | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu |
| **Arapahoe** Unit 3 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Arapahoe** Unit 4 | Natural Gas Operation | 600 tpy (12 month rolling average) by 12/31/2014 | Natural Gas operation 12/31/2014 | 1.28 tpy (12 month rolling average) | Fabric Filter Baghouse* 0.03 lbs/MMBtu<br><br>Natural Gas operation 12/31/2014 |

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

[36] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[37] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[38] 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

# Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

## 7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species. A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

## 7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018. More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

**Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP**

**Colorado Mandatory Class I Federal Areas**

**Uniform Progress Summary in Haze Index Metric**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | 20% Best Days | | |
|---|---|---|---|---|---|---|---|---|
| | Worst Days Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2018 URP delta from Baseline [dv] | 2018 Modeling Projection [dv] | CMAQ Modeling % Towards 2018 URP | Best Days Baseline Condition [dv] | 2018 CMAQ Modeling Results [dv] | 2018 CMAQ Modeling Below Baseline? |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

## 7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or "tags" to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged. The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

## 7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas.

The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

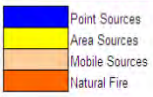
For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

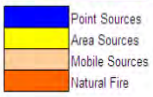
**Figure 7-2 Summary of PSAT Modeling for 2018**

**WRAP - PM Source Apportionment Technology (PSAT) Modeling Results**

*Results based on 2018b Modeling*

| Class I Area | 2018 Sulfate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area | | | | | 2018 Nitrate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Sources* | 1st | 2nd | 3rd | 4th | Sources* | 1st | 2nd | 3rd | 4th |
| Great Sand Dunes National Park & Preserve |  | OD 38.2% | CO 9.7% | NM 8.1% | MEX 7.9% |  | OD 28.9% | NM 27.2% | CO 12.3% | CEN 8.8% |
| Mesa Verde National Park |  | OD 35.4% | NM 17.2% | MEX 11.3% | AZ 10.2% |  | NM 60.2% | CO 12.3% | OD 9.7% | AZ 9.7% |
| Mount Zirkel & Rawah Wilderness Areas |  | OD 29.3% | CO 20.9% | WY 9.2% | UT 7.6% |  | CO 41.6% | OD 17.8% | UT 14.1% | WY 10.3% |
| Rocky Mountain National Park |  | OD 29.1% | CO 23.5% | WY 7.7% | CEN 7.2% |  | CO 33.7% | OD 15.8% | WY 11.0% | UT 5.9% |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas |  | OD 34.9% | NM 13.2% | MEX 10.7% | PO 9.1% |  | NM 43.7% | OD 19.7% | CA 14.1% | AZ 9.9% |
| Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas |  | OD 40.1% | MEX 10.8% | AZ 6.8% | NM 6.1% |  | OD 55.0% | UT 20.0% | CO 15.0% | NM 10.0% |




*Notes:*
*'OD' denotes Outside Domain*
*'CEN' denotes the Central Regional Air Partnership (CENRAP)*
*'MEX' denotes the country of Mexico*
*'PO' denotes the Pacific Offshore*

** Boundary Conditions not included in Pie Charts*

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

**Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018**

**Change in Modeled Concentration for Colorado Share**

***Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)***

| Class I Area | Year | Total SO4 [ug/m3] | Colorado SO4 [ug/m3] | Colorado Share SO4 | Colorado Sulfate Change | Total NO3 [ug/m3] | Colorado NO3 [ug/m3] | Colorado Share NO3 | Colorado Nitrate Change |
|---|---|---|---|---|---|---|---|---|---|
| Great Sand Dunes National Park & Preserve | 2002 | 0.440 | 0.057 | 13% | | 0.116 | 0.017 | 15% | |
| | 2018 | 0.442 | 0.043 | 10% | -25% | 0.114 | 0.014 | 12% | -18% |
| Mesa Verde National Park | 2002 | 0.665 | 0.013 | 2% | | 0.249 | 0.026 | 10% | |
| | 2018 | 0.644 | 0.009 | 1% | -31% | 0.269 | 0.033 | 12% | +27% |
| Mount Zirkel & Rawah Wilderness Areas | 2002 | 0.649 | 0.175 | 27% | | 0.214 | 0.085 | 40% | |
| | 2018 | 0.621 | 0.130 | 21% | -26% | 0.185 | 0.077 | 42% | -9% |
| Rocky Mountain National Park | 2002 | 0.760 | 0.238 | 31% | | 0.339 | 0.128 | 38% | |
| | 2018 | 0.677 | 0.159 | 23% | -33% | 0.273 | 0.092 | 34% | -28% |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 2002 | 0.484 | 0.024 | 5% | | 0.080 | 0.004 | 5% | |
| | 2018 | 0.484 | 0.018 | 4% | -25% | 0.071 | 0.005 | 7% | +25% |
| Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas | 2002 | 0.428 | 0.028 | 7% | | 0.020 | 0.004 | 20% | |
| | 2018 | 0.424 | 0.021 | 5% | -25% | 0.020 | 0.003 | 15% | -25% |

# Chapter 8 Reasonable Progress

## 8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented.

## 8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[39] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling.

[39] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

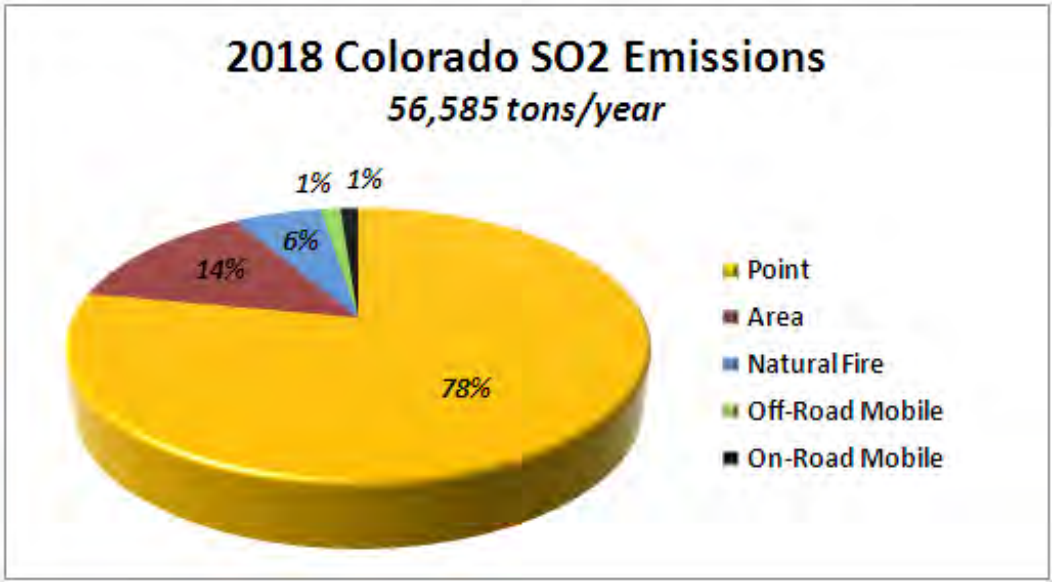
This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in Section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in Section 8.2.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects "on-the-books (OTB)" and "on-the-way (OTW)" emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

**Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018**

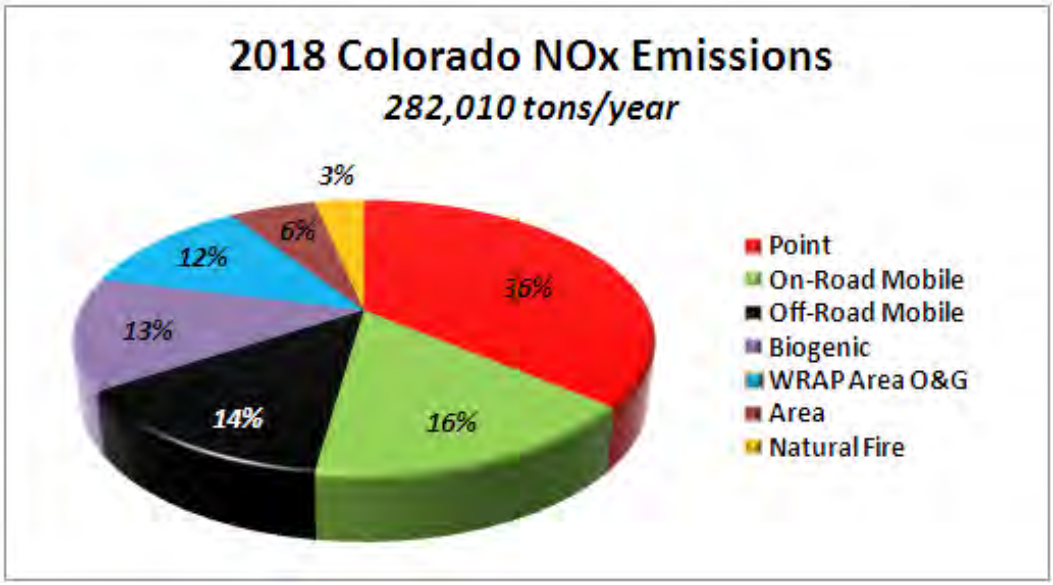


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

**Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018**




Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period.

NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period. The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

## 8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

### *8.3.1 Oil and Gas Heater Treaters*

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

### *8.3.2 Reciprocating Internal Combustion Engines*

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides ($NO_x$; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). $NO_x$ are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation Number 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation Number 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation Number 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado's emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for the NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ. A detailed 4-factor analysis for RICE can be found in Appendix D.

### *8.3.3 Combustion Turbines*

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see Section 8.3 for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period.

There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

| Facility – Turbine | Total 2006 – 2008 Averaged NOx Annual Emissions (tpy) | Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy) | Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy) | Greater than *de minimis* levels? |
|---|---|---|---|---|
| Front Range Power Plant – Turbine #1 | 159.6 | 2.9 | 4.9 | Yes – NOx only |
| Front Range Power Plant – Turbine #2 | 147.9 | 2.8 | 4.9 | Yes – NOx only |

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively. There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels. Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits. A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

## 8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[40].

[40] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as "significant" sources for purposes of reasonable progress.

**Figure 8-3: Point Sources with >100 TPY of Emissions**

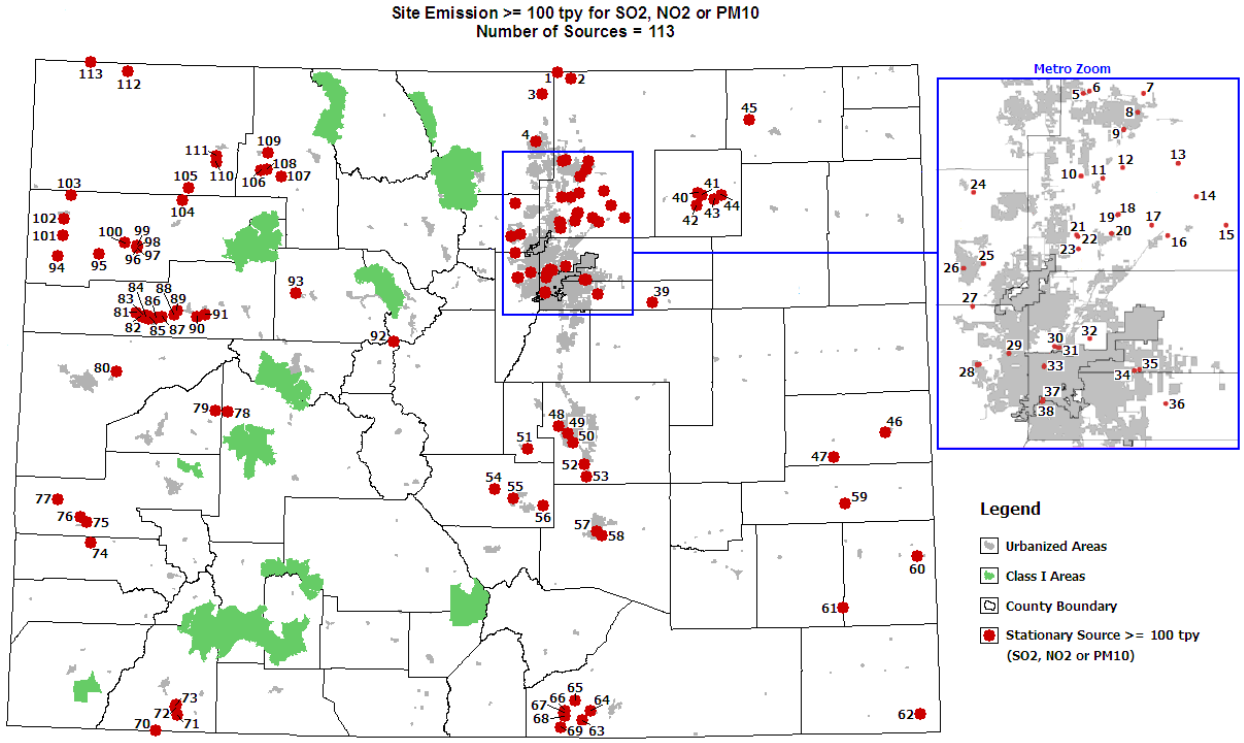


**Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20**

*ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)*

| Count | FACILITY NAME | SO2 [tpy] | NO2 [tpy] | PM10 [tpy] | Q [tpy] | Closest CIA | d [km] | Q/d |
|---|---|---|---|---|---|---|---|---|
| 1 | PLATTE RIVER POWER AUTHORITY - RAWHIDE | 854 | 1,808 | 134 | 2,796 | Rocky Mnt NP | 56.0 | 49.9 |
| 2 | CEMEX INC. - LYONS CEMENT | 87 | 2,479 | 418 | 2,984 | Rocky Mnt NP | 24.8 | 120.3 |
| 3 | PUBLIC SERVICE CO - VALMONT | 749 | 2,355 | 58 | 3,162 | Rocky Mnt NP | 34.8 | 90.9 |
| 4 | COLORADO ENERGY NATIONS CORPORATION | 2,626 | 1,786 | 42 | 4,453 | Rocky Mnt NP | 54.5 | 81.7 |
| 5 | PUBLIC SERVICE CO - CHEROKEE | 7,116 | 10,205 | 261 | 17,581 | Rocky Mnt NP | 65.3 | 269.2 |
| 6 | PUBLIC SERVICE CO - ARAPAHOE | 2,496 | 2,922 | 178 | 5,595 | Rocky Mnt NP | 73.3 | 76.3 |
| 7 | PUBLIC SERVICE CO - PAWNEE | 13,073 | 4,645 | 193 | 17,911 | Rocky Mnt NP | 155.7 | 115.0 |
| 8 | COLORADO SPRINGS UTILITIES - DRAKE | 8,431 | 3,826 | 251 | 12,507 | Great Sand Dunes NP | 114.0 | 109.7 |
| 9 | COLORADO SPRINGS UTILITIES - NIXON | 3,883 | 2,656 | 129 | 6,668 | Great Sand Dunes NP | 104.4 | 63.9 |
| 10 | AQUILA INC. - W.N. CLARK STATION | 1,480 | 869 | 44 | 2,393 | Great Sand Dunes NP | 58.7 | 40.8 |
| 11 | HOLCIM (US) INC. PORTLAND CEMENT | 372 | 2,589 | 288 | 3,250 | Great Sand Dunes NP | 66.0 | 49.2 |
| 12 | PUBLIC SERVICE CO - COMANCHE | 13,854 | 8,415 | 178 | 22,447 | Great Sand Dunes NP | 84.5 | 265.6 |
| 13 | TRI STATE GENERATION - NUCLA | 1,509 | 1,716 | 101 | 3,327 | Black Canyon NP | 70.6 | 47.1 |
| 14 | PUBLIC SERVICE CO - CAMEO | 2,586 | 1,051 | 112 | 3,760 | Black Canyon NP | 70.6 | 53.2 |
| 15 | PUBLIC SERVICE CO - HAYDEN | 2,657 | 7,694 | 284 | 10,634 | Mt Zirkel WA | 31.6 | 336.5 |
| 16 | TRI STATE GENERATION - CRAIG | 3,586 | 16,807 | 235 | 20,628 | Flat Tops WA | 47.7 | 432.4 |
| | Totals: | 65,358 | 71,821 | 2,906 | | | | |

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation Number 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (Unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit.
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (Unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler.
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); Unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For Unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of Unit 3 by 2018 satisfies the PM RP requirements in this planning period; for Unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (Unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (Units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (Unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources.
10. The state has determined that the Black Hills Energy Clark Power Plant (Units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source.
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source.
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source.
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation Number 3.
15. The PSCo Hayden Power Plant (Units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that Unit 3 is subject-to-RP and has conducted an emission control analysis for the unit.

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

## 8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,

(2) The time necessary for compliance,

(3) The energy and non-air quality environmental impacts of compliance, and

(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

### *8.5.1 Rationale for Point Source RP Determinations*

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

***8.5.1.1 The costs of compliance***. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized and the State's consideration of this factor for each source is presented in detail in Appendix D.

***8.5.1.2 The time necessary for compliance***.

Regulation Number 3, Part F, Section VI.B.4. Requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

***8.5.1.3 The energy and non-air quality environmental impacts of compliance***. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described.

***8.5.1.4 The remaining useful life of the source***. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation Number 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

***8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP.*** The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented and in Appendix D.

***8.5.1.6 Overview of the RP Determinations for Each Source.*** This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate. When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[41] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

[41] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[42]

[42] Air Quality Control Commission Regulation Number 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[43] The $5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed $100 million per unit.[44] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[45] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[46] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

[43] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

[44] *See, e.g.*, Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[45] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[46] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

### *8.5.2 Point Source RP Determinations*

The following summarizes the RP control determinations that will apply to each source.

**Table 8-2 RP Control Determinations for Colorado Sources**

| Emission Unit | Assumed** NOx Control Type | NOx Emission Limit | Assumed** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Rawhide** Unit 101 | Enhanced Combustion Control* | 0.145 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **CENC** Unit 3 | No Control | 246 tons per year (12-month rolling total) | No Control | 1.2 lbs/MMBtu | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **Nixon** Unit 1 | Ultra-low NOx burners with Over-Fire Air | 0.21 lb/MMBtu (30-day rolling average) | Lime Spray Dryer | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Clark** Units 1 &2 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Holcim - Florence** Kiln | SNCR | 2.73 lbs/ton clinker (30-day rolling average)<br><br>2,086.8 tons/year | Wet Lime Scrubber* | 1.30 lbs/ton clinker (30-day rolling average)<br><br>721.4 tons/year | Fabric Filter Baghouse*<br>246.3 tons/year |
| **Nucla** | No Control | 0.5 lb/MMBtu (30-day rolling average) *** | Limestone Injection* | 0.4 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 3 | SNCR | 0.28 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.15 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.013 lb/MMBtu filterable PM<br><br>0.012 lb/MMBtu PM10 |
| **Cameo** | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe. The following presents an overview of Colorado's RP control determinations:

### *8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101*

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

**SO2 RP Determination for PRPA Rawhide Unit 101**

*Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of $SO_2$ scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 $SO_2$ scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.

- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state. The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Rawhide Unit 101 – SO2 Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Fuel switching – NG | 906 | $237,424,331 | $262,169 |

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

| SO2 Control Method | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
|---|---|---|
| Daily Maximum (3-yr) | 0.11 | |
| Existing Dry FGD | 0.09 | 0.01 |
| Dry FGD – tighter limit | 0.07 | 0.03 |
| Fuel switching – NG | 0.00 | 0.87 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

**Particulate Matter RP Determination for PRPA Rawhide**

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx RP Determination for PRPA Rawhide**

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Rawhide Unit 101 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| ECC | 448 | $288,450 | $644 |
| SNCR | 504 | $1,596,000 | $3,168 |
| Fuel switching – NG | 545 | $237,424,331 | $435,681 |
| SCR | 1,185 | $12,103,000 | $10,214 |

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | NOx Annual Emission Rate (lb/MMBtu) | 98$^{th}$ Percentile Impact (Δdv) |
|---|---|---|
| Daily Maximum (3-yr) | 0.302 | |
| ECC | 0.126 | 0.45 |
| SNCR | 0.121 | 0.46 |
| Fuel Switching – NG | 0.118 | 0.47 |
| SCR | 0.061 | 0.59 |

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State's RP determination. Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV. Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in Section 8.4. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit ( 0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state. A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

### *8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3*

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

**SO2 RP Determination for CENC – Boiler 3**

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| CENC Boiler 3 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI – Trona | 147 | $1,340,661 | $9,114 |
| Fuel Switching – Natural Gas | 245 | $1,428,911 | $5,828 |

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

**Particulate Matter RP Determination for CENC – Boiler 3**

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for CENC – Boiler 3**

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfired air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| CENC Boiler 3 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| FGR | 33.7 | $1,042,941 | $30,929 |
| SNCR | 50.6 | $513,197 | $10,146 |
| Fuel switching – NG | 84.3 | $1,428,911 | $16,950 |
| ROFA w/ Rotamix | 77 | $978,065 | $9,496 |
| Regenerative SCR | 96.3 | $978,065 | $10,160 |
| High temperature SCR | 125.6 | $1,965,929 | $15,651 |
| Low temperature SCR | 144.5 | $2,772,286 | $19,187 |

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in Section 8.4. All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in Section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

### *8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1*

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

**SO2 RP Determination for CSU – Nixon**

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Nixon Unit 1 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI – Trona | 2,473 | $9,438,692 | $1,997 |
| Dry FGD @ 78% control (0.10 lb/MMBtu annual average) | 3,215 | $12,036,604 | $3,744 |
| Dry FGD @ 85% control (0.07 lb/MMBtu annual average) | 3,392 | $13,399,590 | $3,950 |

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Nixon – Unit 1 | |
|---|---|---|
| | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.45 | |
| DSI | 0.18 | 0.44 |
| Dry FGD (LSD) | 0.10 | 0.46 |
| Dry FGD (LSD) | 0.07 | 0.50 |

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% $SO_2$ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton $SO_2$ removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

### Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for $PM/PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

### NOx RP Determination for CSU – Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Nixon Unit 1 - $NO_x$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Ultra-low NOx Burners (ULNBs) | 471 | $567,000 | $1,203 |
| Overfired Air (OFA) | 589 | $403,000 | $684 |
| ULNBs+OFA | 707 | $907,000 | $1,372 |
| Selective Non-Catalytic Reduction (SNCR) | 707 | $3,266,877 | $4,564 |
| ULNB/SCR layered approach | 1,720 | $11,007,000 | $6,398 |
| Selective Catalytic Reduction (SCR) | 1,720 | $11,010,000 | $6,400 |

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Nixon – Unit 1 | |
|---|---|---|
| | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.26 | |
| ULNB | 0.21 | 0.15 |
| OFA | 0.19 | 0.15 |
| ULNB+OFA | 0.18 | 0.16 |
| SNCR | 0.18 | 0.16 |
| ULNB + SCR | 0.07 | 0.24 |
| SCR | 0.07 | 0.24 |

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement. The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the RP determination.

However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1. A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

### *8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2*

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shut down 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

### *8.5.2.5 RP Determination for Holcim's Florence Cement Plant*

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of $NO_X$, $SO_2$, and $PM/PM_{10}$ emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for $PM/PM_{10}$, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for $SO_2$, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-$NO_X$ precalciner, indirect firing, Low-$NO_X$ burners, staged combustion and a Linkman Expert Control System for $NO_X$, and by the use of good combustion practices for both $NO_X$ and $SO_2$.In addition to the kiln system/main stack emissions, there are two other process points whose $PM/PM_{10}$ emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill.

Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses. Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion $NO_X$ controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a $SO_2$ emission rate of 99.17 lbs/hour, a $NO_X$ emission rate of 837.96 pounds per hour (lbs/hour), and a $PM_{10}$ emission rate of 19.83 lbs/hour. The modeling indicates a $98^{th}$ percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current $PM_{10}$ emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

**$SO_2$ RP Determination for Holcim Portland Plant – Kiln System**

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the $SO_2$ emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2).

The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for $SO_2$. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of $SO_2$ per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline $SO_2$ value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber.

The RP analysis provides sufficient basis to establish a short-term $SO_2$ emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of $SO_2$ per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

**Particulate Matter RP Determination for Holcim Portland Plant – Kiln System**

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding $PM_{10}$ emissions rates. The facility is currently permitted to emit 246.3 tpy of $PM_{10}$ from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of $PM_{10}$ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for $PM_{10}$). The actual kiln system $PM_{10}$ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of $PM_{10}$ per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for $PM_{10}$, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of $PM_{10}$ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of $PM_{10}$ per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change.

The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates ($NO_3$) followed by sulfates ($SO_4$).The contribution of $PM_{10}$ to the total visibility impairment was insignificant in the analysis. The level of $PM_{10}$ emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of $PM_{10}$ emissions from the kiln system on visibility impairment, the state has determined that no additional $PM_{10}$ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of $PM_{10}$ (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source.

Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the $PM_{10}$ emissions.

**$NO_X$ RP Determination for Holcim Portland Plant – Kiln System**

There are a number of technologies available to reduce $NO_X$ emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-$NO_X$ burners, staged combustion, a low-$NO_X$ precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing $NO_X$ emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable "available" control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: "However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns."

Based on our research and EPA's analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000°F) for reducing $NO_X$ to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4$^{th}$ quarter of 2006.

Holcim estimated that $NO_X$ emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

| NOx Control Technology | Estimated Control Efficiency | 30-day Rolling Average Emissions (lb/ton of Clinker) | Annual Controlled NOx Emissions (tpy) |
|---|---|---|---|
| Baseline NOx Emissions | - | 4.97 | 3,185.7* |
| SNCR w/ existing LNB | 45%** | 2.73 | 2,086.8 |

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

| Holcim Portland Plant – Kiln System | | | | |
|---|---|---|---|---|
| NOx Control Technology | NOx Emission Reduction (tons/yr) | Annualized Cost ($/yr) | Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
| Baseline NOx Emissions | - | | | |
| SNCR w/existing LNB (45% control) | 1,098.9 | $2,520,000* | $2,293 | - |

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed $NO_X$ RP limitations. The following table lists the projected visibility improvements for $NO_X$ controls, as identified by Holcim:

| Holcim Portland Plant – Kiln System | | |
|---|---|---|
| NOx Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (Δdv) |
| Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.814 | N/A |
| SNCR w/ existing LNB (45% overall $NO_X$ control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr $NO_X$, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.526 | 0.288 |

For the kiln, the state has determined that SNCR w/existing LNB is the best $NO_X$ control system available with $NO_X$ RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most $NO_X$ reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement. A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

### *8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility*

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 RP Determination for Nucla – Unit 4**

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs.

Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis. The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Nucla Unit 4 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Limestone Injection Improvements | 526 | $914,290 | $4,161 |
| Spray Dry Absorber (dry FGD) | 1,162 | $7,604,627 | $6,547 |
| Limestone Injection Improvements + dry FGD | 1,254 | $9,793,222 | $7,808 |

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage. There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period. Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

**PM10 RP Determination for Nucla – Unit 4**

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for Nucla – Unit 4**

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year. The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

**Additional Analyses of SO2 and NOx Controls for Nucla**

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options.

A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

**Requirements for Nucla Station**

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual $NO_x$ limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review for the Nucla facility can be found in Appendix D.

### *8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3*

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 RP Determination for Craig – Unit 3**

*Dry FGD Upgrades* - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of $SO_2$ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.
- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent.
- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Craig – Unit 3 | |
|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.33 | |
| Dry FGD | 0.15 | 0.26 |
| Dry FGD | 0.07 | 0.38 |

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

**PM10 RP Determination for Craig – Unit 3**

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for Craig – Unit 3**

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3. The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Craig Unit 3 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 853 | $4,173,000 | $4,887 |
| SCR | 4,281 | $29,762,387 | $6,952 |

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period. The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
|---|---|---|
| Daily Maximum (2nd half 2009) | 0.365 | |
| SNCR | 0.240 | 0.32 |
| SCR | 0.070 | 0.79 |

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions. Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in Section 8.4.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in Section 8.4. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs. A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

### *8.5.2.8 RP Determination for Public Service Company's Cameo Station*

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

# Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated. This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

## 9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its' apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:

(1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;

(2) Emission limitations and schedules for compliance to achieve the RP goal;

(3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;

(5) Source retirement and replacement schedules;

(6) Enforceability of emission limitations and control measures; and

(7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following Sections 9.2 and 9.3 address these LTS requirements.

## 9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized.

### *9.2.1 Existing Impairment*

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation Number 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule.

As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation Number 3. In addition, Regulation Number 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado's requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

#### *9.2.1.1 Mt. Zirkel Wilderness*

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

#### *9.2.1.2 BART and Emission Limitations*

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation Number 3 result in new control requirements for these units to meet BART.

### *9.2.1.3 Monitoring*

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of 'before and after emission reductions' will be met.

### *9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance*

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation Number 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

### *9.2.1.5 Ongoing Air Pollution Programs*

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

### *9.2.2 Prevention of Future Impairment*

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Colorado considers it's NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

### *9.2.3 Smoke Management Practices*

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado's Regulation Number 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation Number 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation Number 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

### *9.2.4 Federal Land Manager Consultation and Communication*

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

## 9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation Number 3, as described in Section 9.2.1, and a commitment to utilize the FETS to track fire data as described in Section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

## 9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

### *9.4.1 Impacts on Other States*

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

**Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands**

| Mandatory Class I Area | Modeled Visibility Improvement by 2018 [deciviews] | Colorado's Contribution to 2018 Nitrate | 2018 Total Nitrate Impacts at CIA | Colorado's Nitrate Contribution to 2018 Haze at CIA | Colorado's Contribution to 2018 Sulfate | 2018 Total Sulfate Impacts at CIA | Colorado's Total Sulfate Contribution to 2018 Haze at CIA | Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA |
|---|---|---|---|---|---|---|---|---|
| Bandelier National Monument | 0.3 | 5.1% | 6.6% | 0.3% | 1.2% | 15.5% | 0.2% | 0.5% |
| Canyonlands National Park | 0.5 | 6.9% | 9.5% | 0.7% | 2.3% | 14.8% | 0.3% | 1.0% |

*All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.*

### *9.4.2 Impacts from Other States*

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

### *9.4.3 Document Technical Basis for RPGs*

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

### *9.4.4 Identify Anthropogenic Sources*

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

### *9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs*

Following is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
    - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
    - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
    - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
    - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
    - Part A – Federal NSPS's adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
    - Part B – state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
    - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized.
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only
- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) – state-only

- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

https://www.colorado.gov/cdphe/aqccAs recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

Table 9-1 shows the designation status for all current and former non-attainment areas.

**Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT**

| PM10 | Redesignations | Plan Amendments |
|---|---|---|
| Aspen | AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03 | 10-year update: AQCC approved 12/16/10 |
| Canon City | AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00 | 10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009 |
| Denver | AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02 | Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08 |
| Lamar | AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05 | None |
| Pagosa Springs | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | 10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Steamboat Springs | AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04 | |
| Telluride | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | 10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| **Carbon Monoxide** | **Redesignations** | **Plan Amendments** |
| Colorado Springs | AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99 | - Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01<br>- Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04<br>- 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Denver | AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02 | - Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08 |
| Ft. Collins | AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03 | 10-year update: AQCC approved 12/16/10 |

| | | |
|---|---|---|
| Greeley | AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99 | - Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05<br>- 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Longmont | AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99 | - Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08 |
| **Ozone** | **Redesignations** | **Plan Amendments** |
| Denver/Northern Front Range | AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01<br><br>Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05 | - 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0<br>- 8-hour OAP updated 12/17/06 by AQCC to incorporate Regulation Number 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08<br>- Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009 |
| **Lead** | **Redesignations** | **Plan Amendments** |
| Denver | EPA redesignated Denver attainment in 1984 | |
| **Nitrogen Dioxide** | **Redesignations** | **Plan Amendments** |
| Denver | EPA redesignated Denver attainment in 1984 | |

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

### *9.4.6 Measures to Mitigate the Impacts of Construction Activities*

Regulation Numbers 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation Number 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation Number 1, Sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation Number 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

### *9.4.7 Smoke Management*

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation Number 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[47]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation Number 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted.

[47] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation Number 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;
- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: https://www.colorado.gov/cdphe/smoke-management-permits

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation Number 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation Number 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

### *9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures*

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Numbers 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

### *9.4.9 Source Retirement and Replacement Schedules*

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation Number 3. Unless otherwise indicated in those chapters or in Regulation Number 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

### *9.4.10 Anticipated Net Effect on Visibility*

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable.

Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources. Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

**Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP**

**Colorado Mandatory Class I Federal Areas**

**Uniform Progress Summary in Haze Index Metric**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | 20% Best Days | | |
|---|---|---|---|---|---|---|---|---|
| | Worst Days Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2018 URP delta from Baseline [dv] | 2018 Modeling Projection [dv] | CMAQ Modeling % Towards 2018 URP | Best Days Baseline Condition [dv] | 2018 CMAQ Modeling Results [dv] | 2018 CMAQ Modeling Below Baseline? |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

**Uniform Rate of Progress for 2018**

**Projected Amount of Progress by 2018 towards URP**

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
- 2010 BART alternative: 37,488 tons/year
- 2010 RP: 12,624 tons/year

Total: 70,846 tons/year

Also, 3,321 tons of additional NOx reductions will occur by 2021 due to a more stringent emission limit at Craig Unit 1 adopted in 2014. The revised total is 74,167 tons/year of visibility impairing pollutants reduced (due to BART and RP measures).

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

## Figure 9-3 Emission Reductions Achieved by BART Determinations

**BART Emission Control Analysis**

**NOx BART - SCR**

| Source | SCR Capital Costs | Annualized SCR Costs | SCR NOx Reduced [tpy] | SCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Hayden - Unit 2 | $ 71,780,853 | $ 12,321,491 | 3,032 | $ 4,064 | 0.82 | 23 (Zirkel) |
| Hayden - Unit 1 | $ 61,938,167 | $ 10,560,612 | 3,120 | $ 3,385 | 1.12 | 48 (Zirkel) |
| Craig - Unit 1 (SCR @ 78% reduction) | $ 209,548,000 | $ 25,036,709 | 4,048 | $ 6,184 | 1.01 | 41 (Mt. Zirkel) |
| Craig - Unit 2 (SCR @ 74% Reduction) | $ 209,552,000 | $ 25,036,709 | 3,975 | $ 6,299 | 0.94 | 41 (Mt. Zirkel) |

**NOx BART - SNCR**

| Source | SNCR Capital Costs | Annualized SNCR Costs | SNCR NOx Reduced [tpy] | SNCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| CEMEX - Kiln | $ 600,000 | $ 1,636,636 | 846 | $ 1,934 | 0.40 | 14 (RMNP) |

**NOx BART - Other**

| Source | Capital Costs | Annualized Costs | NOx Reduced [tpy] | NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Drake - Unit 5 (ULNB w/OFA) | $ 2,895,672 | $ 288,844 | 215 | $ 1,342 | 0.08 | > 0 (RMNP) |
| Drake - Unit 6 (ULNB w/OFA) | $ 3,340,318 | $ 337,751 | 509 | $ 664 | 0.20 | > 3 (RMNP) |
| Drake - Unit 7 (ULNB w/OFA) | $ 4,500,232 | $ 461,217 | 749 | $ 616 | 0.26 | > 3 (RMNP) |
| CENC (TriGen) - Unit 4 LNB, w/SOFA | $ 4,284,900 | $ 678,305 | 214 | $ 3,170 | 0.08 | 3 (RMNP) |
| CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR | $ 6,556,888 | $ 1,739,825 | 354 | $ 4,919 | 0.26 | 14 (RMNP) |
| CEMEX - Dryer T5 Permit Limits | $ - | $ - | 0 | $ - | 0.00 | none |

**SO2 BART**

| Source | Capital or O&M Costs | Annualized Costs | SO2 Reduced [tpy] | SO2 Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day) | $ 6,000,000 | $ 1,340,663 | 762 | $ 1,761 | 0.12 | 2 (RMNP) |
| Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day) | $ 38,000,000 | $ 6,665,771 | 2,368 | $ 2,816 | 0.24 | 3 (RMNP) |
| Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day) | $ 44,166,000 | $ 9,577,538 | 3,764 | $ 2,544 | 0.39 | 6 (RMNP) |
| Hayden - Unit 1 Tighten Emission Limit to 0.13 | $165,000 parts & $110,000 O&M | $ 141,150 | 61 | $ 2,318 | 0.01 | >12 (Mt. Zirkel) |
| Hayden - Unit 2 Tighten Emission Limit to 0.13 | $165,000 parts & $110,000 O&M | $ 141,150 | 39 | $ 3,629 | 0.05 | >8 (Mt. Zirkel) |

| | | |
|---|---|---|
| *TOTAL CAPITAL COST* | $ 1,082,813,031 | |
| *TOTAL ANNUALIZED COST* | $ 146,037,789 | |
| **TOTAL NOX REDUCED** | **25,085** | *tons/year* |
| **TOTAL SO2 REDUCED** | **6,993** | *tons/year* |
| **TOTAL COMBINED POLLUTANTS REDUCED** | **32,079** | *tons/year* |

## Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

| Facility | NOx Emissions Average 2006-2008 (tpy) | NOx Emissions from Alternative (TPY) | Total NOx Emissions Reduced (TPY) | SO2 Emissions Average 2006 -2008 (tpy) | SO2 Emissions from Alternative (TPY) | Total SO2 Emissions Reduced (TPY) |
|---|---|---|---|---|---|---|
| Arapahoe | | | | | | |
| Unit 3 | 1,770 | 0 | | 925 | 0 | |
| Unit 4 | 1,148 | 900[48] | | 1,765 | 1.28 | |
| Cherokee | | | | | | |
| Unit 1 | 1,556 | 0 | | 2,221 | 0 | |
| Unit 2 | 2,895 | 0 | | 1,888 | 0 | |
| Unit 3 | 1,866 | 0 | | 743 | 0 | |
| Unit 4 | 4,274 | 2,063[49] | | 2,135 | 7.81[50] | |
| Valmont | 2,314 | 0 | | 758 | 0 | |
| Pawnee | 4,538 | 1,403[51] | | 13,472 | 2,406[52] | |
| Totals | 20,361 | 4,366 | 15,995 | 23,908 | 2,415 | 21,493 |

**Total Emission Reductions Achieved: 37,488 tons per year**

[48] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[49] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[50] Emissions at 0.0006 lb SO2/MMBtu

[51] Emissions at 0.07 lb NOx/MMBtu

[52] Emissions at 0.12 lb SO2/MMBtu

## Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

**RP Emission Control Analysis**

**NOx RP - SCR**

| Source | SCR Capital Costs | Annualized SCR Costs | SCR NOx Reduced [tpy] | SCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| | | | | | | |

**NOx RP - SNCR**

| Source | SNCR Capital Costs | Annualized SNCR Costs | SNCR NOx Reduced [tpy] | SNCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Craig - Unit 3 (SNCR @ 15% Reduction) | $ 13,139,000 | $ 4,173,000 | 854 | $ 4,886 | 0.32 | 6 (Mt. Zirkel) |
| Holcim Cement (establish limit) | not estimated | $ 2,520,000 | 1,028 | $ 2,451 | 0.23 | 5 (GSDNP) |

**NOx RP- Other**

| Source | Capital Costs | Annualized Costs | NOx Reduced [tpy] | NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 861 | n/a | n/a | n/a |
| Cameo - Unit 1 (Shutdown) | n/a | n/a | 516 | n/a | n/a | n/a |
| Cameo - Unit 2 (Shutdown) | n/a | n/a | 624 | n/a | n/a | n/a |
| CENC - Boiler 3 (none) | n/a | n/a | n/a | n/a | n/a | n/a |
| Nixon - Unit 1 (ULNB w/Overfire Air) | $ 3,822,000 | $ 970,000 | 707 | $ 1,372 | 0.15 | 2 (RMNP) |
| Nucla (none) | n/a | n/a | n/a | n/a | not modeled | not modeled |
| Rawhide - Unit 1 (enchanced combustion control) | $ 1,180,000 | $ 288,450 | 448 | $ 644 | 0.35 | 18 (RMNP) |

**SO2 RP**

| Source | Capital Costs | Annualized Costs | SO2 Reduced [tpy] | SO2 Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 1,457 | n/a | n/a | n/a |
| Cameo - Unit 1 (Shutdown) | n/a | n/a | 849 | n/a | n/a | n/a |
| Cameo - Unit 2 (Shutdown) | n/a | n/a | 1,769 | n/a | n/a | n/a |
| CENC - Boiler 3 (none) | n/a | n/a | n/a | n/a | n/a | n/a |
| Craig - Unit 3 (tighten existing emission limit) | none | none | 0 | n/a | 0.26 | 6 (RMNP) |
| Holcim Cement (establish limit) | not estimated | not estimated | 0 | n/a | - | n/a |
| Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling) | $ 96,160,000 | $ 12,036,604 | 3,215 | $ 3,744 | 0.46 | 11 (RMNP) |
| Nucla (none) | n/a | n/a | n/a | n/a | not modeled | not modeled |
| Rawhide - Unit 1 (no technically feasible options) | n/a | n/a | n/a | n/a | n/a | n/a |

**PM RP**

| Source | Capital or O&M Costs | Annualized Costs | PM Reduced [tpy] | PM Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 72 | n/a | n/a | n/a |
| Cameo - Units 1 & 2 (Shutdown) | n/a | n/a | 225 | n/a | n/a | n/a |

| | | |
|---|---|---|
| *TOTAL CAPITAL COST* | $ 114,301,000 | |
| *TOTAL ANNUALIZED COST* | $ 19,988,054 | |

| | | |
|---|---|---|
| TOTAL NOX REDUCED | 5,038 | *tons/year* |
| TOTAL SO2 REDUCED | 7,290 | *tons/year* |
| TOTAL PM REDUCED | 297 | *tons/year* |
| TOTAL COMBINED POLLUTANTS REDUCED | 12,624 | *tons/year* |

Of these 74,121 tons of SO2 and NOx reduced due to BART and RP, approximately 47,821 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 presents this analysis for each of the BART and RP sources.

**Figure 9-6 Difference between the WRAP and Final BART/RP Emissions for NOx and SO2**

**Additional NOx and SO2 Reductions**

***Difference between PRP2018b and Proposed BART/RP***

| PLANT | PRP 2018b NOx [tpy] | 2018 BART/RP NOx [tpy] | Difference [tpy] | PRP 2018b SO2 [tpy] | 2018 BART/RP SO2 [tpy] | Difference [tpy] |
|---|---|---|---|---|---|---|
| AQUILA, INC. - W.N. CLARK STATION | 1,090 | - | (1,090) | 1,322 | - | (1,322) |
| CEMEX, INC. - LYONS CEMENT PLANT | 901 | 901 | - | 97 | 95 | (2) |
| COLORADO SPRINGS UTILITIES - NIXON PLT | 2,331 | 1,650 | (681) | 4,073 | 907 | (3,166) |
| COLORADO SPRINGS UTILITIES - DRAKE PLT | 3,669 | 2,789 | (880) | 2,701 | 1,590 | (1,111) |
| HOLCIM (US) INC. PORTLAND PLANT | 1,859 | 2,087 | 228 | 393 | 721 | 328 |
| PLATTE RIVER POWER AUTHORITY - RAWHIDE | 3,912 | 1,418 | (2,494) | 927 | 913 | (14) |
| PUBLIC SERVICE CO - CAMEO (shutdown) | - | - | - | - | - | - |
| PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only) | - | 900 | 900 | - | 1 | 1 |
| PUBLIC SERVICE CO - VALMONT | 2,279 | - | (2,279) | 879 | - | (879) |
| PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4) | 5,998 | 1,813 | (4,185) | 5,214 | 8 | (5,206) |
| PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2) | 4,317 | 250 | (4,067) | 1,750 | - | (1,750) |
| PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2) | 6,143 | 4,602 | (1,541) | 3,686 | 2,953 | (733) |
| PUBLIC SERVICE CO COMANCHE PLT (Unit 3) | 2,600 | 2,600 | - | 3,250 | 3,250 | - |
| PUBLIC SERVICE CO HAYDEN PLT | 7,307 | 1,341 | (5,966) | 2,898 | 2,541 | (357) |
| PUBLIC SERVICE CO PAWNEE PLT | 3,942 | 1,403 | (2,539) | 2,225 | 2,406 | 181 |
| TRI STATE GENERATION CRAIG (Units 1 & 2) | 10,974 | 2,539 | (8,435) | 2,117 | 1,952 | (165) |
| TRI STATE GENERATION CRAIG (Unit 3) | 5,825 | 4,839 | (986) | 1,823 | 1,863 | 40 |
| TRI STATE GENERATION NUCLA | 1,753 | 2,167 | 414 | 1,325 | 1,325 | 0 |
| TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5) | 1,185 | 722 | (463) | 2,624 | 2,762 | 138 |
| TRIGEN - COLORADO ENERGY CORPORATION (Unit 3) | 159 | 222 | 63 | 170 | 379 | 209 |
| | **66,243** | **32,243** | **(34,000)** | **37,473** | **23,666** | **(13,807)** |
| | | | **Combined Reductions from NOx and SO2 Controls [tpy]:** | | | **(47,808)** |

These substantial additional emission reductions will further the amount of progress achieved. Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

## 9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

**Figure 9-7 Reasonable Progress Goals for Each Class I Area**

**Colorado Mandatory Class I Federal Areas**

**Uniform Progress Summary in Haze Index Metric**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | 20% Best Days | | |
|---|---|---|---|---|---|---|---|---|
| | Worst Days Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2018 URP delta from Baseline [dv] | 2018 Modeling Projection [dv] | CMAQ Modeling % Towards 2018 URP | Best Days Baseline Condition [dv] | 2018 CMAQ Modeling Results [dv] | 2018 CMAQ Modeling Below Baseline? |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

**Reasonable Progress Goals for 2018**

**No Degradation of Visibility for the Best Days**

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated in Section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources.

Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures. Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable.

In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

## Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

**Colorado Mandatory Class I Federal Areas**

**Number of Years to Attain Natural Conditions**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2064 Natural Conditions [dv] | Total Haze Delta (Baseline-2064 NC) [dv] | Haze Program Period [yrs] | Haze Program Reduction Rate [dv/yr] | 2018 Modeling Projection [dv] | 2018 Modeling <= 2018 UPG? | Recast Reduction Rate [dv/yr] | Number of years to NC [yrs] | New NC Goal [year] |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 6.66 | 6.12 | 60 | 0.102 | 12.20 | No | 0.041 | 148 | 2152 |
| Mesa Verde National Park | 13.03 | 11.58 | 6.81 | 6.22 | 60 | 0.104 | 12.50 | No | 0.038 | 164 | 2168 |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 6.08 | 4.44 | 60 | 0.074 | 9.91 | No | 0.044 | 102 | 2106 |
| Rocky Mountain National Park | 13.83 | 12.27 | 7.15 | 6.68 | 60 | 0.111 | 12.83 | No | 0.071 | 94 | 2098 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 6.21 | 4.12 | 60 | 0.069 | 9.83 | No | 0.036 | 115 | 2119 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 6.06 | 3.55 | 60 | 0.059 | 8.98 | No | 0.045 | 79 | 2083 |

The following figures for Mesa Verde National Park illustrate the re-calculations.

## Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

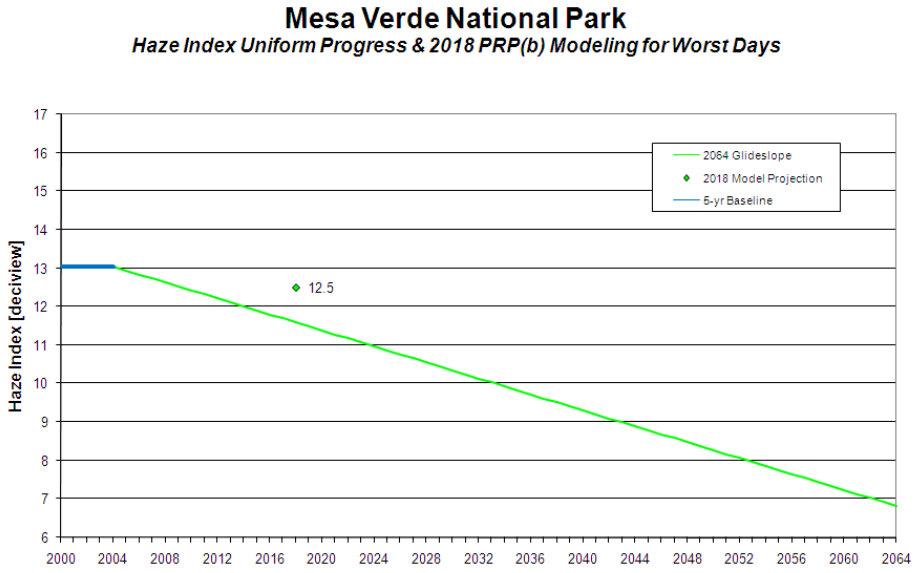
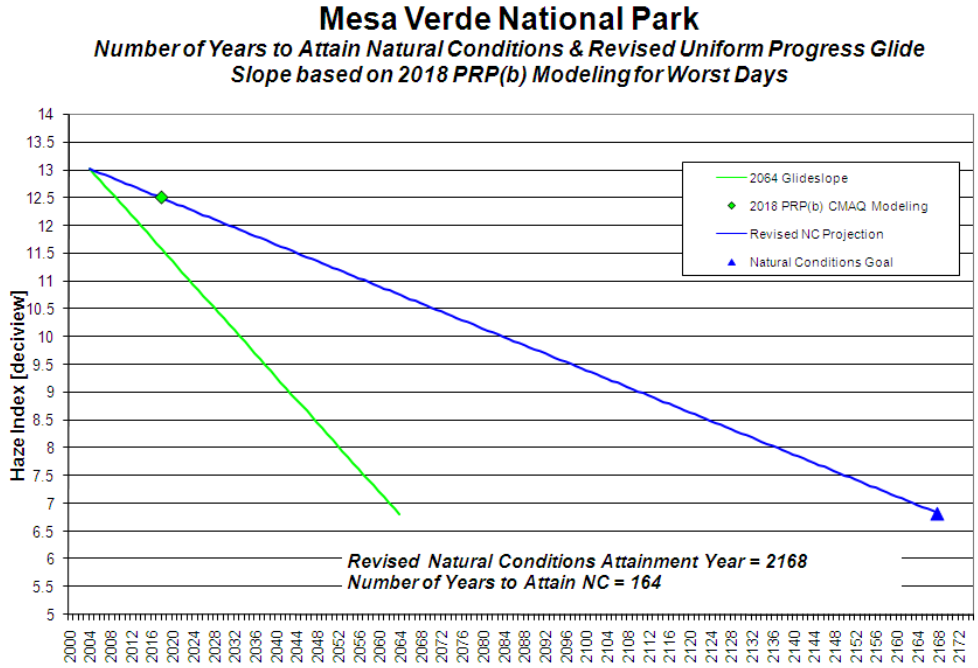


**Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions**



# Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

## 10.1 Future Consultation Commitments

### *10.1.1 FLM Consultation*

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

### *10.1.2 Tribal Consultation*

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

### *10.1.3 Inter-state Consultation/Coordination*

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado's emissions may reasonable be anticipated to cause or contribute to visibility impairment in those State's federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

### *10.1.4 Regional Planning Coordination*

As per the requirements of [51.308(c)(1)(i)], Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
3. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

## 10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state.
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy.
3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period.

4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period.
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP.
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions.
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado. The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

## 10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.
4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

## 10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized.

### *10.4.1 Current Visibility Conditions*

Colorado commits to determine and report current visibility conditions for the most and least impaired days using the most recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

### *10.4.2 Long Term Strategy Effectiveness*

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

### *10.4.3 Affirmation of or Revisions to Reasonable Progress Goals*

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this Section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

# Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

## 11.1 Class I Area Technical Support Documents (TSDs)

TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

## 11.2 Other Technical Support Documents

In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

*Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

## 11.3 Long-Term Strategy Review Update

In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

*Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy*, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

## List of Appendices –

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

# APPENDIX A

## *Regional Haze State Implementation Plan*

***Periodic Review of Colorado RAVI Long Term Strategy***

# LONG-TERM STRATEGY REVIEW

# OF

# COLORADO'S STATE IMPLEMENTATION PLAN FOR CLASS I AREA VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

**July 2007**
**(updated October 2007)**

## I. STATE OF COLORADO'S PHASE I STATE IMPLEMENTATION PLAN FOR CLASS I VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

The various elements of Phase I of Colorado's Class I Visibility State Implementation Plan are spread throughout Colorado Air Quality Control Commission Regulation No. 3. All of the components of the Visibility SIP are important to long-term visibility protection of Class I areas in the State and are integrated in varying degrees into the LTS review and revision protocol. Therefore, each of the components is briefly discussed in this section.

### A. Existing Impairment.

The AQCC's Regulation No. 3, *Stationary Source Permitting and Air Pollution Emission Notice Requirements,* includes provisions to address impairment within Class I areas reasonably attributable to existing major sources.

Regulation No. 3 Part D §XIV.D provides for an affected FLM or the Division to certify visibility impairment in a Class I area due to an existing stationary source. Existing sources regulated under this program are those that were not in operation prior to August 7, 1962 nor for which construction was commenced on or after August 7, 1977, which have the potential to emit 250 tons or more of an air pollutant regulated by the Division.

The FLM or the Division may certify at any time that impairment exists in any Class I area. If the Division reasonably attributes the impairment to an existing source, the Division must conduct a BART analysis and determine if additional emission limitations are required. If so, the source must apply for a BART permit from the Division. Once the permit is granted, the source

must limit its emissions on a schedule not to exceed five years. At the time of Colorado's Visibility SIP development, the FLMs did not indicate that potentially reasonably attributable types of visibility impairment were present in any of Colorado's Class I areas. The Division concurred with the finding. However, in 1993 the USFS certified visibility impairment in the Mt. Zirkel Wilderness in northwest Colorado.[1] The certification has subsequently been resolved and is discussed below in section II.B.1.a.

**B. New Source Review.**

Applicants for permits to operate as a major source must demonstrate that the proposed source will not have an adverse impact on visibility in any Class I area. Regulation 3 Part D §XIII.A sets forth a schedule for the participation of affected FLMs and consultation with the Division in the review process of such an analysis as part of the Prevention of Significant Deterioration (PSD) permitting application process.

The Division is required to consider any FLM determinations that the proposed source would have an adverse impact on visibility in the Class I area (Regulation 3 Part D §V.A.6 and XIII.C). The Division may independently make its own determination. If the Division does determine that its own or the FLM's analysis demonstrates that an adverse impact would occur, the Division shall not issue the permit.

In addition to the analysis, a source may be required to conduct monitoring to establish the condition of, and impact on, air quality related values (AQRVs) in the Class I area that may be affected. Monitoring can be required both before completing a permit application to construct and during the construction and operation of the source (Regulation 3 Part D §VI.A.3, §VI.A.4, §XIII.B).

**C. Consultation With Federal Land Managers.**

Regulation No. 3 provides for participation by the FLMs in the new source review process. The FLMs may also make recommendations to the Division concerning integral vistas, identify impairment in any Class I area, and provide consultation concerning elements considered for inclusion in the monitoring strategy. The Division also is required to consult with the FLMs during development and review of the Phase I Long-Term Strategy (Regulation 3 Part D §XIV.F.1.a).

**D. Monitoring Strategy.**

The monitoring strategy in the SIP is based on the following four goals:

1. To provide information for new source visibility impact analysis.

2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.

3. To determine actual effects from the operation of new major sources or modifications to major sources on nearby Class I areas.

4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major sources must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permitees will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the FLMs or the Division certify existing impairment in a Class I area, the Division will determine if the documented visibility impairment can be reasonably attributed to emissions from an existing local stationary source. In making this determination, the Division will consider all available data, including the following:

1. Data supplied by the FLM;

2. The number and type of sources likely to impact visibility in the Class I area;

3. The existing emissions and control measures on the source(s);

4. The prevailing meteorology near the Class I area; and

5. Any modeling that may have been done for other air quality programs.

If available information is not sufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s), the Division will initiate cooperative studies. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

**E. Phase I Long-Term Strategy.**

The Phase I LTS is that portion of the Visibility SIP that is the State's long-term strategy for making reasonable progress toward remedying existing and preventing future visibility impairment within the context of the Phase I program.

EPA regulations require the State to: (1) develop a long-term strategy; (2) coordinate its LTS with existing plans and goals, including those of federal land managers, that may affect impairment in any Class I area; (3) demonstrate why the LTS is adequate for making reasonable progress toward the national goal and state why the minimum factors (listed in the next paragraph) were or were not addressed in developing the LTS; (4) consider the time necessary for compliance as well as the economic, energy, and non-air quality environmental impacts of compliance, the remaining useful life of any affected existing source, as well as the effect of new sources; (5) review its strategy no less frequently than every 5 years and consult with federal land managers during this process; and (6) report to EPA and the public on progress achieved toward the national visibility goal.

During development of the LTS the State must consider, at a minimum, the following six factors:

- *Emission reductions due to ongoing air pollution control programs*. For example, the attainment and maintenance of National Ambient Air Quality Standards in the Denver metropolitan area and other non-attainment areas throughout Colorado may reduce visibility impairment in a number of Class I areas in the State. If this is the case, the State should explain how this would contribute to reasonable progress.

- *Additional emission limitations and schedules for compliance*. For example, states may have to control other sources causing impairment not covered by BART to make reasonable progress toward the national goal.

- *Measures to mitigate the impacts of construction activities*. This recognizes that nearby construction activities can contribute to impairment in Class I areas. If this appears to be a problem in Colorado, then the State should explain in its LTS what measures it will take to mitigate these impacts.

- *Source retirement and replacement schedules*. The construction of new sources, which will ensure the early or scheduled retirement of older, less well-controlled sources, can greatly aid progress toward the national visibility goal over the long term.

- *Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for this purpose.* The LTS should discuss measures that would constitute reasonable progress in relation to this issue.

- *Enforceability of emission limitations and control measures*. In some situations the enforceability of proposed or actual emission limitations and control measures on sources causing existing impairment may be an issue.

**F. Colorado's LTS History and the Current Review and Revision.**

Since the time the Colorado Visibility SIP was adopted by the AQCC in 1987, the LTS has been amended and/or reviewed on eight occasions:

- The original 1987 LTS was reviewed and revised in August 1992.

- After the 1993 certification of impairment at the Mt. Zirkel Wilderness Area, the EPA requested an informal LTS status report, which was supplied in December 1993.

- The 1996-97 LTS was completed in two stages:

    - August 1996 -- focusing entirely on the Mt. Zirkel Wilderness Area certification of impairment and the incorporation of emission limitations for the Hayden Generating Station; and

    - April 1997 -- addressing all other issues.

- The LTS was comprehensively reviewed again in January 1999, but a SIP revision was not found to be necessary.

- Following the Craig Consent Decree in early 2001, the LTS was again amended in April 2001 incorporating emission limitations, schedules, and reporting requirements for Craig Units 1 and 2. The State, the USFS, and EPA concluded that the 1993 certification of visibility impairment involving Mt. Zirkel Wilderness Area was resolved.[2,3]

- The February 2002 LTS was comprehensively reviewed and the LTS portion of the SIP was updated and reorganized into a more readable format.

- The November 2004 LTS was also a comprehensive review and minor SIP revision update.

Past LTS reviews and SIP revisions are available from the Division.

This current review is a report on the activities, actions, processes, and progress made with respect to the seven review categories within the context of the existing Phase I LTS, adopted by the Commission in November 2004. Colorado believes, based on an assessment of the State's achievements with respect to these seven categories, that the current Reasonably Attributable Class I visibility program of the State of Colorado achieves reasonable progress toward the national visibility goal under Phase I of the visibility protection program.

In a separate document is a SIP revision to the reasonably attributable part of the LTS. The revision is a relatively small series of amendments intended to reflect current conditions and plans.

## II. REVIEW OF COLORADO'S LONG-TERM STRATEGY

### A. STATE AND EPA REQUIREMENTS

State regulations require the Division to periodically report to the AQCC on the progress made toward the national visibility goal via the Phase I SIP. This report to the AQCC and the public is being submitted to fulfill these requirements. A SIP revision is contained in a separate document.

EPA regulations require that the State provide this report to the public and the Administrator of EPA. Both EPA and State regulations require the report to include an assessment of:

1. The progress achieved in remedying existing impairment of visibility in any Class I area.

2. The ability of the long-term strategy to prevent future impairment of visibility in any Class I area.

3. Any change in visibility since the last such report, or in the case of the first report, since plan approval, including an assessment of existing conditions.

4. Additional measures, including the need for SIP revisions that may be necessary to ensure reasonable progress toward the national visibility goal.

5. The progress achieved in implementing BART and meeting other schedules set forth in the long-term strategy.

6. The impact of any exemption from BART granted to any facility.

7. The need for BART to remedy existing impairment in an integral vista declared since plan approval.

### B. STEP-BY-STEP REVIEW

Each element of the review is presented in detail below.

#### 1. PROGRESS IN REMEDYING EXISTING IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

The Phase I Class I Visibility SIP is focused on source-specific or plume-type impairment from single or small groups of stationary sources, consistent with Phase I of the implementation of EPA's visibility program.

**a. Visibility Impacts in the Mt. Zirkel Wilderness.**

In July 1993, the USFS certified visibility impairment in the Mt. Zirkel Wilderness Area and named the Hayden and Craig power stations as suspected sources.[1] As noted, upon certification by a federal land manager of visibility impairment in a Class I area, the Division must determine if it can "reasonably attribute" the visibility impairment to one or more existing stationary

sources. If so, the Division must conduct a BART analysis and as a result may order emission limitations for each pollutant at the facilities.

The Division considered existing information available at the time of the USFS certification of impairment to determine if it could make a decision to reasonably attribute visibility impairment within the MZWA to the Hayden and/or Craig generating stations. The Division concluded that existing information was insufficient to reasonably attribute. The Division's response was to collaboratively develop with other stakeholders the $3.5 million Mt. Zirkel Visibility Study (MZVS) in order to collect additional information. The MZVS was concluded in July 1996.[4]

For a complete review of the activities, studies, and events that have occurred in relation to this environmental matter, see the April 1997 and January 1999 LTS reviews (available from the Division). Below is a summary of the how the certification of impairment has been resolved.

**(i). Hayden Station.**

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. On May 21, 1996, the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice executed an agreement -- the Hayden Consent Decree.[5] On May 22, 1996, the Decree was filed in federal district court. The court approved it on August 19, 1996. The Decree was intended to resolve a number of issues, including a successful Sierra Club lawsuit against the Hayden Station, the needs of the State's visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC on August 15, 1996. The State believes that these significant emission reductions effectively eliminate the sulfate and primary plume related visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has concluded that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.[6]

The construction of Hayden's control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, $SO_2$, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit and the permit has been issued and the Consent Decree has been terminated.

**(ii). Craig Generating Station (Yampa Project).**

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999. After Hayden was

resolved in August 1996, attention turned to Craig Station Units 1 and 2. The Mt. Zirkel Visibility Study (MZVS) indicated to the Division that sulfate haze from Yampa Valley power plants occasionally entered the MZWA and along with regional haze contributed to visibility impairment. Thus, the focus to resolving the Craig Station portion of the certification was on reducing $SO_2$, the precursor pollutant of sulfate, from Craig Station Units 1 and 2. The State preferred to resolve the visibility certification through negotiated settlement. If settlement seemed unlikely, the State was prepared to resolve the certification using the available regulatory tools. At a meeting in late 1996 between the State, Craig Owners, and EPA, the State agreed to temporarily delay pursuing regulatory action in order to foster the collaboration needed to jointly develop additional information on various $SO_2$ emission reduction options and associated cost. Craig Station Units 1 and 2 at the time achieved 65% $SO_2$ control; both EPA and the State believed that an improvement in the degree of control would resolve the certification. A joint study, known as the Craig Station Flue Gas Desulfurization Study (Craig FGD Study), became the focus for a negotiated settlement. The information could also be used as part of a BART determination if needed. The study was completed in August 1999.[7]

There were other issues involved and parties concerned with emissions from Craig Station Units 1 and 2. The USFS has strong concerns about local emissions of $SO_2$ and NOx that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. A 1996 Colorado statute provides FLMs with an opportunity to assert impairment to Class I areas by air pollution adversely affecting non-visibility related qualities of the area, such as the aquatic ecosystem.[8] The USFS did not trigger the law with an assertion related to MZWA and was awaiting the outcome of the resolution of the visibility certification and/or global settlement of all issues. In addition, the Sierra Club initiated a citizen lawsuit under the Clean Air Act in late 1996 directed against Craig Station Units 1 and 2 regarding opacity issues.

In Fall 1999, the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. On September 22, 1999, EPA issued a SIP call to Colorado indicating the State had twelve months to resolve the certification regarding Craig Station Units 1 and 2.[9] The Craig Owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. The court approved the agreement on March 19, 2001. The State resolved the certification of impairment for Units 1 and 2 of Craig Station by adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The USFS concluded that, "the proposed reductions of both sulfur dioxide and nitrogen oxides will resolve all Forest Service issues relative to the Craig Stations and our 1993 Certification of Impairment."[10] The SIP was amended by the AQCC on April 19, 2001[2] and EPA published final approval of the SIP amendment after a public comment period.[3] Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, $SO_2$, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit. The permit has been issued and the Consent Decree terminated.

**(iii). Other Stationary Sources and the MZWA.**

The Division has found no evidence that other stationary sources potentially subject to

BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA under Phase I of the EPA visibility program. The USFS certification of visibility impairment, related to the Phase I program, has been completely resolved. Regional haze that impacts any Colorado Class I area**s**, including MZWA, are addressed in the regional haze SIP.

**(iv). Monitoring and the MZWA.**

It is important to track the effect of the emission reductions at Hayden and Craig generating stations on visibility impairment near the Wilderness as well as on acid levels in sensitive lakes and the snowpack. Funding for and the collection of these data are provided variously by the USFS, U.S. Geological Survey, EPA, and the Division. Table 1 below provides a brief overview of monitoring activities in and around MZWA.

**Table 1**
**Long-Term Visibility and Non-Visibility Air Quality Related Value Measurements In and Near the Mt. Zirkel Wilderness Area**

| Instrument, Measurement, or Sampler | 1. Sponsor<br>2. Funding<br>3. History | Purpose |
|---|---|---|
| Continuous $SO_2$ monitor at Buffalo Pass Tower* | 1. Colorado Air Pollution Control Division<br>2. $9,800/year by CAPCD<br>3. 9/97 through present. | Measures frequency and magnitude of $SO_2$ "hits" at Buffalo Pass as an indicator of the presence of Craig and Hayden emissions and potential impacts at the Mt. Zirkel Wilderness Area. The monitor provides hourly average $SO_2$. The purpose of the monitor is to determine whether trends are occurring as emissions change at Hayden and Craig 20 and 40 miles away, respectively, in the Yampa Valley. |
| Continuous ambient nephelometer at Buffalo Pass Tower* | 1. US Forest Service<br>2. $9,600/year by USFS<br>3. 1994 through present. | Measures frequency and magnitude of visibility episodes (the nephelometer measures light scattering, a component of visibility) at Buffalo Pass. This measurement provides hourly average light scattering but is subject to significant weather interferences. |
| Automatic camera system | 1. US Forest Service<br>2. $5,280/year by USFS<br>3. 10/90 through present | Three 35mm slides are taken each day and archived. The visual information can be used to document various types of visibility conditions and matched/collated with instrumental measurements. |
| IMPROVE aerosol monitor at Buffalo Pass Tower* | 1. Initially USFS, now EPA, as part of the national IMPROVE visibility monitoring network.<br>2. $14,000/year by EPA (for supplies and analysis)<br>$33,000/year by USFS (for support of all Buffalo Pass Tower monitoring operations) | Measurements include 1-in-3 day sampling, 24-hour filter based PM2.5 (chemically speciated) and PM10 (mass only). Light extinction reconstruction is calculated from the various aerosol constituents. Measurement of overall reconstructed light extinction is used for episode identification as well as trends. These reconstructed extinction data will be compared between the before and after periods. While this measure is not as prone to weather interferences as the nephelometer, other challenges in analyzing these data include changes in regional emissions, climatic variation, wildfire, and the nature |

| Instrument, Measurement, or Sampler | 1. Sponsor<br>2. Funding<br>3. History | Purpose |
|---|---|---|
| | 3. 1994 through present | of trying to distinguish episodic change in a 24-hour average. |
| National Acid Deposition Program (NADP) sampler at Buffalo Pass Tower*. | 1. USFS<br>2. $12,288/year by USFS<br>3. 1984 through present | Measurement of acid precipitation-related chemical constituents. The network collects data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium). |
| Mercury deposition sampler at Buffalo Pass Tower* | 1. USFS<br>2. $12,000/year by USFS<br>3. 1997 through present | Mercury deposition sampling is done through the NADP program. This site is sponsored and funded by USFS. The purpose is to measure mercury deposition. The sample is collected weekly and sent to the NADP's Central Analytical Laboratory. |
| Snowpack chemistry sampling in March or April of each year prior to spring snowmelt. | 1. USGS, NPS, USFS<br>2. $115,000/year<br>3. 1990 through present | Annual measurement of snowpack chemistry prior to spring snowmelt and the release of acids during the "spring acid pulse." The U.S. Geological Survey has been monitoring snowpack chemistry at more than 50 locations throughout the Rocky Mountain region, extending from northern New Mexico to northern Montana, annually since 1993. There are 20 sites in Colorado, including several in and near the Mt. Zirkel Wilderness. Some sites in Colorado have been monitored since 1990. The purpose of the monitoring is to: 1) have an integrated measurement of acid deposition and snow chemistry over the snow accumulation months in high altitude areas associated with sensitive high altitude aquatic ecosystems; 2) determine whether trends are occurring in the snowpack chemistry; and 3) provide indicators of regional and/or local source emission changes. |
| Lake sampling in Mt. Zirkel Wilderness (and 2 other wilderness areas) during summer and fall. | 1. USFS/CDPHE/ USGS<br>2. $62,000<br>3. 1983 through present | Measurements of acid precipitation-related chemical constituents as well as overall measures such as hydrogen ion, pH, and buffering capacity of 3 lakes in the Mt. Zirkel Wilderness. The purpose of the long-term monitoring of these lakes is to: 1) determine the natural variance in chemistry of the lakes; 2) determine whether trends are occurring in the chemistry of lakes in the Mt. Zirkel Wilderness, and 3) provide information on the ambient chemistry of lakes in the Wilderness. |

*Buffalo Pass monitoring tower is at the southern end of the Mt. Zirkel Wilderness.

The measurements provide a reasonably comprehensive network to track the emission changes

through different parts of key environmental systems, including atmospheric emissions, visibility, precipitation, acid deposition, mercury deposition, snowpack and aquatic ecosystems.

**(v). Analysis of the Effects of the Hayden Generating Station Emission Reductions.**

Using the data collected from the network described above, the Division and the USGS completed an analysis during 2004-2005 of the effects of the emission reductions at the Hayden Generating Station. At that time, Craig had just completed its emission capture upgrade and there were insufficient data to analyze to assess the additional effects of the Craig project. Therefore, the analysis focused on the reductions at the Hayden Generating Station. A final report will be completed during 2009 on the effects of the reductions at Craig as well as an assessment of the combined effect of the decreases in emissions from both facilities.

*Study Design.* Environmental data were compared between a period "before" Hayden was controlled versus a period "after" Hayden was controlled**.**

The period before controls were installed at Hayden is defined as 1995 through 9/24/98. 1995 is chosen as the beginning of the before period even though data extends earlier for a number of data sets. The before period is purposely constrained to limit the influence of regional emission changes over time as well as climate variation.

Unit 1's boiler was brought down on 9/25/98 to begin the tieing-in and integration of its various air pollution control systems. Unit 1 was re-started with emission controls on December 21, 1998. Unit 2's boiler was brought down on 3/7/99. It was re-started on May 20, 1999. However, intermittent problems with the $SO_2$ controls could not be fixed until November 16, 1999. The Craig Generating Station (Yampa Project) began its upgrades on September 13, 2003. The three periods (i.e., before, during, after) are summarized in Table 2 below. Only the before and after periods were analyzed and compared.

**Table 2**
**The Before, During and After Periods**

| **Period** | **Dates** | **What** |
|---|---|---|
| Before | 1995 through 9/24/98 | This is the period before Hayden's pollution controls began operating |
| During (not analyzed) | 9/25/98 through 11/16/99 | Pollution control equipment was being tied-in, integrated and de-bugged. |
| After | 11/17/99 through 9/12/03 | Hayden's equipment in routine operation and Craig had not yet begun its tie-in period. |

*Confounding Factors.* Because the collection of environmental data occurs in the real world,

rather than in a laboratory where other changes can be held constant, there are several influences the data analysts were aware might confound or mask the signal of Hayden's emission change. All of the factors below contribute to make it more difficult to find and attribute the changes due solely to Hayden.

- Climate
  - The before period was wetter than average and the after period was drier than average. There was a 30-40% decrease in precipitation between the two periods depending on measurement location.
- Regional Haze
  - The after period was 17% more hazy. This is largely due to the decrease in precipitation and associated drought. Chemical analyses showed that almost all of the change between the two periods was due to particles from wildfires and increased dust.
- Overall Yampa Valley Emissions
  - Hayden and Craig are in the same valley, therefore, emissions from both must be considered together since analysis techniques can't identify the pollutants from one plant versus the other. Given Hayden's specific reduction and the ongoing operation at Craig (before its upgrade), $SO_2$ decreased in the Yampa Valley by 48% and NOx increased 7%.
- Regional Emission Changes
  - Not only was there an emission change at Hayden, but large emission reductions of $SO_2$ also occurred in the southwestern part of the U.S. For example: Arizona/39%, New Mexico/27%, Wyoming/18%, Texas/15%.
- Atmospheric Chemistry
  - The atmospheric chemistry converting invisible $SO_2$ gas to visible sulfate particles is not linear. That is, a one unit decrease in $SO_2$ may not lead to a one unit decrease in sulfate.

*Results.*

- Emissions
  - Sulfur dioxide ($SO_2$) removal at Hayden has always been at least 85% over 30 and 90 day rolling averages since the compliance period began. Nitrogen oxides (NOx) have decreased approximately 50% annually. The new particulate control system has completely eliminated the occasional black smoke-plume episodes that previously occurred.
- Ambient $SO_2$ as measured at Mt. Zirkel Wilderness Area
  - Decreased 40% due to the reductions at Hayden.
- Haze at Mt. Zirkel Wilderness Area
  - Increased 17% due to the drought and increases in regional haze. This would have been worse without the reductions at Hayden.
- Sulfate Particulate Haze
  - Overall decrease of 20% at Mt. Zirkel Wilderness Area.
  - Peak sulfate episodes were eliminated in the after data. This is a very important finding because it is the worst days that hamper enjoyment of clear visibility.

    - It is estimated that approximately half of the overall decrease is due to Hayden's reductions. The other half is due to the regional scale reductions in $SO_2$.
- Acid Deposition Measurements
    - Decrease in sulfuric acid deposition of approximately 20%.
        - Looking at other measurement sites, this decrease in sulfuric acid *only* occurred at acid deposition sites downwind of Hayden.
    - Overall decrease in acid deposition at all sites, however, most of this is drought related due to an increase in dust elements in the rain and snow that buffer acids.
- Snowpits
    - Small decrease in sulfuric acid at pits downwind from Hayden.
    - Overall decrease in acidity, again due to more dust elements in the snowpack.
- Lakes
    - No change due to emission reductions in before versus after periods. This is expected because response time to an emission reduction of $SO_2$ in a watershed is several years. Effects of drought were also visible in lake acidity (i.e., less acid due to increased dust elements).

In spite of the big challenges nature and other anthropogenic changes piled onto the study design, the USGS and the APCD see a strong signal decrease in episodic visibility impairing sulfate and acidic wet sulfate in and near the Mt. Zirkel Wilderness Area from the emission reductions at Hayden Generating Station.

**b. Regional haze.**

EPA published its final regional haze rule in July 1999.[11] This review of the Phase I SIP is not related formally to the regional haze program. Nevertheless, such haze exists at all Colorado Class I areas and is the subject of the larger regional haze SIP document within which this LTS review is embedded and coordinated.

**c. Ongoing Air Pollution Control Programs.**

Since the November 2004 LTS review/report several activities in ongoing air pollution control programs have occurred that are relevant to this review.

**(i). Rocky Mountain National Park Initiative.**

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Through these efforts significant amounts of data have been collected. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

Two-thirds of the Park is near or above treeline with shallow soils and granitic bedrock that are indicative of a fragile ecosystem environment. This environment is highly susceptible to changes induced by chemical contributions to soils and waters through atmospheric deposition. The Park's enabling legislation and other key Congressional statutes mandate that natural resources at RMNP are to remain unimpaired for future generations. Thus, the Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and ozone by the Early Action Compact and SIP development process.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative's progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP works to: (1) consider all available emission reduction options and programs for nitrogen-related emissions (primarily nitrogen oxides (NOx) and ammonia (NH3)); (2) provide a technical assessment of the state-of-knowledge of deposition components and trends, the emission sources, source areas, and atmospheric transport; (3) determine implementation measures for making progress and mechanisms to evaluate effectiveness of, and incorporation of new, control measures; (4) make recommendations for future needs as necessary to assure continued progress and achievement of Park goals; and (5) incorporate adaptive management principals for the consideration and use of new data and analyses as they become available.

The Plan includes a critical load determination for nitrogen affecting the high alpine ecosystems in the Park that was established prior to the development of this Plan. The critical load for wet nitrogen deposition, set at 1.5 kg/ha/yr, is a threshold value above which significant harmful effects to sensitive ecosystem components occur. The critical load for wet nitrogen deposition east of the Continental Divide in RMNP represents an estimation of the concentration at which excess nitrogen deposition began causing harmful impacts on RMNP ecosystems. The Plan relies on a "glidepath" management approach to achieve the critical load goal in the Park by

the year 2032 with interim milestones to be measured at five-year intervals. The first milestone, set for 2012, works to achieve a reduction that is consistent with an average rate of deposition reduction that will achieve the critical load by the year 2032 and reflects the potential benefit from planned state and federal emission reduction programs.

The NDRP was approved by the AQCC in April 2007. Implementation of the Plan will likely benefit visibility at RMNP to an unknown degree. The Division maintains a website that is a clearinghouse for information related to the Initiative. The full NDRP and other technical documents may be found at
http://www.cdphe.state.co.us/ap/rmnp.html

**(ii). The Four Corners Task Force.**

After many years of concern about emissions growth in the Four Corners area and impacts on nearby Class I areas, the States of New Mexico and Colorado have convened an Air Quality Task Force to work on the air quality issues and challenges facing the Four Corners region. The Four Corners region is rich in coal and oil & gas reserves. Oil & gas production and coal-fired power plants result in large emissions of air pollution that may be degrading air quality. Specific concerns include National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increment compliance, degradation of visibility, and increased deposition.

The U.S. Department of Interior - Bureau of Land Management (BLM) and the U.S. Department of Agriculture - Forest Service (USFS) are currently responding to industry proposals for expanded development of oil and gas production in the region. There are two proposed coal-fired power plants: a 1,500 megawatt plant proposed on Navajo Nation lands and a 300 megawatt plant proposed north of Grants, New Mexico. Additionally, the population in the Four Corners region likely will continue to grow in coming years, resulting in even more air pollution and, specifically, more nitrogen oxide emissions.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to begin to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning.

The Task Force work groups are:

- Oil and Gas,
- Power Plants,
- Other Sources,
- Cumulative Effects, and
- Monitoring.

These workgroups are studying issues and creating lists of options to the Task Force about how to proceed. An executive/steering committee that includes representatives from the states of

Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables are being developed to ensure that all options developed are timely. The task force will work over a two-year period and deliver a final report by December 2007.

The Task Force's website is
http://www.nmenv.state.nm.us/aqb/4C/index.html

**(iii). New Oil and Gas Controls.**

On December 17, 2006, the Colorado Air Quality Control Commission (AQCC) adopted changes to oil & gas industry regulations to reduce emissions of volatile organic compounds (VOCs) from condensate tanks. VOCs are a precursor to ozone formation and secondary organic carbon particulate – a component of visibility degradation.

New control requirements were established for condensate tanks in both the Front Range Early Action Compact Area and statewide. New reporting and recordkeeping requirements were also established. The new requirements are summarized below:

*Control Requirements: Front Range Ozone Early Action Compact (EAC) Area*

- Commencing May 1, 2007, companies in the EAC region must increase the control of VOCs from current 47.5 percent level to 75 percent for the summertime ozone season.
- In addition, there are new reporting and recordkeeping requirements.

*Control Requirements: Statewide*

- Tanks standards: New and existing condensate tanks emitting 20 tons per year or more of VOCs required to control emissions by 95 percent commencing May 1, 2008.
- Glycol Dehydrator controls: New and existing glycol dehydrators emitting more than 15 tons per year of VOCs are required to control emissions by 90 percent commencing May 1, 2008.
- Table 3 contains engine standards for new or relocated engines from out-of-state commencing July 1, 2007.

**Table 3**
**Engine Standards**

| Maximum engine horsepower | Construction or relocation date | NOx g/hp-hr | CO g/hp-hr | NMHC g/hp-hr |
|---|---|---|---|---|
| 100 - 500 hp | January 1, 2008<br>January 1, 2011 | 2.0<br>1.0 | 4.0<br>2.0 | 1.0<br>0.7 |
| Greater than 500 hp | July 1, 2007<br>July 1, 2010 | 2.0<br>1.0 | 4.0<br>2.0 | 1.0<br>0.7 |

Additional information about the new emission controls can be found at http://www.cdphe.state.co.us/ap/oilgas.html

**(iv). Review of Ongoing Programs and Status of Redesignations.**

The most comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2006-2007 Report to the Public. This report in its entirety is included as Attachment 1.

As recently as 1995 Colorado had 12 "non-attainment" areas within the State for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas has also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA has designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 8-hour ozone, though the nonattainment designation has been deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone on Friday, July 20, 2007 appear to have put the nine-county Denver region in violation of the federal health-based, eight-hour standard for ozone. If monitoring results are verified, the region will likely be designated as "nonattainment" for ozone by the U.S. Environmental Protection Agency. A detailed plan to reduce ozone will be developed for submission to the EPA in 2008 by the Colorado Air Pollution Control Division, along with the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization. This new plan, a federally -required State Implementation Plan for ozone, will require further reductions in ozone levels beyond what was required through an earlier Ozone Early Action Compact.

The table below shows the designation status for Colorado non-attainment areas as of April 2007.

**Table 4**
**REDESIGNATION and PLAN AMENDMENT STATUS REPORT – 4/2/07**

| | **Redesignations** | **Plan Amendments** |
|---|---|---|
| **PM10** | | |
| Aspen | AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03 | None |
| Canon City | AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00 | None |
| Denver | AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02 | Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved |

| | **Redesignations** | **Plan Amendments** |
|---|---|---|
| | | 12/15/05; Governor submitted to EPA 9/25/06 |
| Lamar | AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05 | None |
| Pagosa Springs | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | None |
| Steamboat Springs | AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04 | None |
| Telluride | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | None |

| **Carbon Monoxide** | | |
|---|---|---|
| Colorado Springs | AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99 | - Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01<br>- Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 |
| Denver | AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02 | - Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06 |
| Ft. Collins | AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03 | |
| Greeley | AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99 | - Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 |
| Longmont | AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99 | - Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06 |

| | | |
|---|---|---|
| **Ozone** | | |
| Denver /Northern Front Range | AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01<br><br>Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05 | - 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; Governor submitted to EPA 10/06<br>- 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg 7 oil and gas condensate tank and engine requirements. Governor's submittal anticipated<br>-Additional exceedances in 2007. SIP preparation in 2008. |
| **Lead** | | |
| Denver | EPA redesignated Denver attainment in 1984 | |
| **Nitrogen Dioxide** | | |
| Denver | EPA redesignated Denver attainment in 1984 | |

## 2. THE ABILITY OF THE LONG-TERM STRATEGY TO PREVENT FUTURE IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

Generally, the State of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as meeting the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities. In addition, there are specific activities the Division has undertaken.

### a. Modeling Guidance.

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division's expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division's web site at: http://apcd.state.co.us/permits/cmg.html

### b. Smoke Management.

Colorado believes its smoke management program is protective of public health and welfare as well as Class I visibility. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. The program is described below.

#### (i). Regulation No. 9.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. In addition to its permitting requirements, it implements Colorado Senate Bill 01-214 ("Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Therefor") that became law in 2001. The regulation also incorporates permitting and reporting requirements for all users of prescribed fire similar to those in the State's past Smoke Management Memorandum of Understanding (MOU). The AQCC adopted the regulation on January 17, 2002.

Regulation No. 9 is in eight sections:

I. Scope
II. Definitions
III. Open Burning Permit Requirement
IV. General Open Burning Permits
V. Planned Ignition Fire Permits
VI. Unplanned Ignition Fire Permits
VII. Additional Requirements for Significant Users of Prescribed Fire
VIII. Fees

The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement.

After the scope and definitions sections, the rule has several sections regarding permitting and other requirements applicable to open burning of various types. Section IV contains requirements for a general open burning permit and associated permit conditions. Sections V and VI contain the permitting, information, modeling and reporting requirements, as well as a smoke risk categorization, and permit conditions for planned ignition prescribed fires to insure that prescribed fires neither violate National Ambient Air Quality Standards nor have unacceptable visibility impacts. These provisions are similar to the past voluntary agreements among signatories of the expired Colorado Smoke Management MOU for prescribed fire. The regulation, however, applies to <u>all</u> users of prescribed fire above a de minimus level project. The rule also specifies requirements regarding suppression of prescribed fire if monitoring and/or air pollution levels indicate that permit conditions, the burn prescription, and/or air quality standards have been or will be exceeded. The Division's draft permits for large burns with a high smoke-risk are subject to a 30-day public comment period and the opportunity for a public comment hearing before the Commission. The Division will disclose potential visibility impacts of these proposed fires and must consider comments when determining whether to grant, conditionally grant, or deny the final permit.

Sections VII and VIII are the elements of the regulation that implement SB01-214. Section VII addresses how significant users of prescribed fire (i.e., those that own or manage 10,000 acres and generate at least 10 tons of $PM_{10}$ annually from use of prescribed fire) must submit planning documents to the Commission. The regulation identifies the contents of the planning documents. The rule further requires that all such prescribed fire activities of significant users

shall conform to the State standard to "minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable." SB 01-214 directs the Commission to hold a public hearing regarding each planning document and to develop any necessary comments and recommendations to bring the plans into consistency with the State goal. After July 1, 2002 the Division cannot issue open burning permits to significant users for lands whose planning documents and fuel management decision-making are inconsistent with Commission recommendations and comments. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, the Forbes/Trinchera Ranch, and the Denver Water Board.

Fees are discussed in section VIII. No fees are charged for general permits (local authorities may charge fees under their own authority). Significant users of prescribed fire pay fees of $59.98/hour to the Division for review of planning documents. Prescribed fire permitees pay for the cost of the prescribed fire program based on a cost distribution methodology. The Division's Fiscal Officer calculated the cost of the program at the outset of the program beginning in calendar year 2002. The Statement of Basis, Specific Statutory Authority and Purpose of the regulation also specifies the Commission's intent that the Division annually calculate the cost to administer the program and report to the Commission each August on program costs, projections, and revenues. If the cumulative cost varies more than 5% from the total fee amount in regulation, the Division will seek a fee change before the Commission in a properly noticed public hearing. In addition, the Statement indicates that any deficits not be funded by stationary source fees. The current cost of the program as stated in Regulation No. 9 is $174,585.08.

While not included in the rule, it is important to note that the statute also finds the prescribed fires of significant users conducted on lands the primary purpose of which is nonagricultural to be for "commercial purposes". The effect is to subject any such activity conducted without a permit to significantly higher fines than previously (i.e., up to $100/day for "noncommercial purposes" and up to $10,000/day for "commercial purposes").

In March 2004, the Commission approved changes to Regulation No. 9 allowing the permitting of Air Curtain Destructors (ACD) to be used for the narrow purpose of burning wildland fuels generated as a result of projects to reduce the risk of wildfire. The use of ACDs in lieu of pile burning will significantly reduce emissions from defensible space and other types of wildfire risk reduction projects.

**(ii). The Regulation and Visibility Protection.**

Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. For example,

- the potential contribution of such burning to air pollution in the area;

- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;
- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
    - a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. Proposed planned ignition burns are compared to computer model output that indicates the air pollution (including visibility) impacts. A permit is granted only if the modeling run demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides that the Division may impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitees are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitees must indicate whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2006 are available by contacting the Division.

As mentioned above, the regulation requires that the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about the various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. The web site underwent a major revision and updating during 2005. It is located at: http://www.cdphe.state.co.us/ap/smoke/

## 3. CHANGES IN VISIBILITY SINCE SIP APPROVAL AND ASSESSMENT OF EXISTING CONDITIONS

Visibility monitoring is being performed in or near a number of Colorado's Class I areas.

The specific purposes of monitoring may vary, but generally include assessing existing conditions and trends as well as learning more about the sources of visibility impairment in Colorado's Class I areas.

The routine visibility monitoring performed in Colorado's Class I areas are at IMPROVE, IMPROVE Protocol or IMPROVE Look Alike sites. IMPROVE is an acronym that stands for Interagency Monitoring of PROtected Visual Environments. IMPROVE is a cooperative visibility monitoring effort of the EPA, NPS, USF&WS, BLM, USFS, Western States Air Resources Council (WESTAR), Mid-Atlantic Regional Air Management Association (MARAMA), North Eastern States for Coordinated Air Use Management (NESCAUM), and the National Association of Clean Air Agencies (NAACA). IMPROVE Protocol sites are operated using the same equipment, procedures and analytical labs as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE Look Alike sites are operated using the same equipment and procedures but may utilize different labs. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by a sponsoring federal land management agency or state. IMPROVE Look Alike sites may be funded by private industry or other entity. IMPROVE and IMPROVE Protocol sites are operated by the NPS, BLM, or the USFS. The State of Colorado has funded a short-term IMPROVE Look Alike site but does not fund other IMPROVE or IMPROVE Protocol sites. IMPROVE has an extensive web site at: http://vista.cira.colostate.edu/improve. Graphically processed IMPROVE data as well as links to photographic images of various haze levels at Class I areas and meteorological data are found on the Visibility Information Exchange Web System (VIEWS) at: http://vista.cira.colostate.edu/views/

The types of visibility monitoring being performed in Colorado's Class I areas and some of the results of this monitoring are summarized later in this section of the LTS review. The section is divided into three major parts:

a. Monitoring Methods and Network -- a very brief discussion of each of the types of routine visibility monitoring performed in Colorado and a description of the monitoring network in place as of December 2006.

b. Site-By-Site Data Summaries -- summaries of the routine data available as of April 2007 collected by these methods, a short discussion of the data, and of possible data trends of each site (park or wilderness area).

c. Overall Conclusions from the Routine Monitoring -- statements about visibility levels, sources, and trends in Colorado's Class I areas.

**a. Monitoring Methods and the Network.**

Routine visibility monitoring consists of three general components. The first, view monitoring, is used to document the visual quality of a scene. The second component, atmospheric optical monitoring, measures basic optical properties of the atmosphere (e.g., atmospheric extinction, light scattering) that relate to the atmosphere's ability to cause visibility impairment. In some of Colorado's Class I areas atmospheric extinction has been directly

measured with a transmissometer. At one of the monitoring sites, a nephelometer monitors the scattering coefficient of ambient air. The third component of most routine visibility monitoring systems, particle monitoring, measures fine atmospheric particles that are responsible for visibility impairment. This third component is considered the core method for IMPROVE and at each site, at a minimum, is a chemically speciated fine particle monitor. Each general component of monitoring is described in more detail below.

**(i). View Monitoring.**

Camera systems are used to document visibility in a view from a fixed location. A specially constructed camera system automatically takes slides or digital images of a view at regularly scheduled times each day (usually three times per day). The images provide a qualitative record of visibility conditions that exist at a site.

Automated camera systems are in place at the following sites to monitor visibility conditions in or near the following Class I areas (the letters in parentheses below are how each site is referenced within the FLM and IMPROVE data and image management systems):

- Shamrock Mines (SHMI) near the Weminuche Wilderness;
- Maroon Bells-Snowmass Wilderness site in the White River National Forest (MABE); and
- Mt. Zirkel Wilderness (ZIRK).

In the past automated camera systems operated at the following sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Colorado National Monument (COLM);
- Dinosaur National Monument (DINO);
- Great Sand Dunes National Park (GRSA);
- Mesa Verde National Park (MEVE);
- Rocky Mountain National Park (ROMO);
- West Elk Wilderness (WEEL);
- La Garita Wilderness (LAGA);
- Eagles Nest Wilderness (EANE); and
- Weminuche Wilderness (WEMI).

In addition, camera systems have monitored at the following Class II wilderness areas:

- Lost Creek Wilderness (at the Devil's Head Fire Tower) (DEHE); and
- Mount Massive Wilderness (MOMA).

Once a multi-year visual record of site conditions is collected, the camera systems are removed and installed to document conditions at another site. A spectrum of various visibility conditions seen on the slides taken at a given site and relationship to other monitoring if

available are archived onto a photo CD and/or uploaded to web sites. Images are available at: http://www.fsvisimages.com/
and
http://vista.cira.colostate.edu/views/Web/IMPROVE/Data_IMPRPhot.htm

**(ii). Atmospheric Optical Monitoring.**

Atmospheric extinction describes the ability of particles and gases in the atmosphere to attenuate light over a given distance (e.g., per kilometer). Extinction occurs due to the scattering and absorption of light from gaseous and aerosol constituents of the atmosphere. A transmissometer is an optical visibility monitoring device, which can continuously measure atmospheric extinction. The instrument accomplishes the measurement by sending a light beam of known intensity to a distant receiver and measuring the resulting loss of light. A nephelometer directly measures the scattering component of atmospheric extinction.

High relative humidity, rain and fog events reduce visibility. Data collected during periods experiencing such events are often excluded from transmissometer and nephelometer data in order that it reflect anthropogenic influences. Transmissometer data were collected at the following IMPROVE sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Mesa Verde National Park (MEVE), through May 1993; and
- Rocky Mountain National Park (ROMO), through October 2006.

Nephelometer data are collected at:

- Mt. Zirkel Wilderness (MOZI).

**(iii). Particle Monitoring.**

Atmospheric particle monitoring is accomplished by a combination of particle sampling and sample analysis. Simultaneous particulate samples are collected in the four channels of the IMPROVE Particle Sampler: three $PM_{2.5}$ samples (particles less than 2.5 microns in diameter) on different filter types (Teflon, nylon, and quartz) and one $PM_{10}$ sample (particles less than 10 microns in diameter) on a Teflon filter. The filters are subsequently analyzed for total mass, elements, organic and light absorbing carbon, ions, and optical absorption. Particulate monitoring is used to quantify and identify the air pollutants responsible for visibility degradation. Atmospheric extinction can be mathematically reconstructed from these chemically speciated aerosol samples – this is the core method EPA has selected for monitoring haze. Typically, an IMPROVE Sampler takes a 24-hour sample once every three days. The IMPROVE web site contains literature that indicates[12] the overall uncertainty (defined as the ratio of the mean precision from all sources divided by the mean concentration) is 4% to 7% for most variables and >15% for organic carbon. These numbers reflect precision; accuracy is unknown.

Particulate monitoring with an IMPROVE Sampler is performed in or near the following

Colorado Class I areas (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Great Sand Dunes National Monument (GRSA).
- Mesa Verde National Park (MEVE).
- Weminuche Wilderness Area (WEMI).
    - This monitoring site also represents visibility conditions in La Garita Wilderness and Black Canyon of the Gunnison Wilderness.
- Shamrock Mines (SHMI).
    - This site was installed in 2005 and is a supplemental site for assessing impacts to the Weminuche Wilderness Area from emissions activity in the Four Corners Area.
- Snowmass/Maroon Bells Wilderness site in the White River National Forest (WHRI).
    - This monitoring site also represents visibility conditions in West Elk Wilderness, Eagles Nest Wilderness, and Flat Tops Wilderness.
- Mount Zirkel Wilderness Area (MOZI).
    - This site also represents visibility conditions in the Rawah Wilderness.
- Rocky Mountain National Park (ROMO).
- Ripple Creek Pass (RICR).
    - This site is to the north of the Flat Tops Wilderness. It is funded privately by Shell Oil Company and operated by Air Sciences, Incorporated.
- Douglas Pass (DOPA).
    - This site operated at the top of Douglas Pass near the Utah border for over 2 years. It was funded by the Colorado Governor's Office of Energy Management and Conservation and operated by Air Sciences, Incorporated.

**b. Routine Monitoring Data Summary.**

A number of the visibility monitoring sites in Colorado's Class I areas have been in operation for several years. Table 5 below is a summary of the types of monitoring and the dates when monitoring has occurred at each of the sites.

**Table 5**
**Routine Visibility Monitoring**

| SITE | CAMERA | TRANSMIS-SOMETER | NEPHELO-METER | IMPROVE PARTICULATE MONITORING | SITE TYPE[1] |
|---|---|---|---|---|---|
| BLCA Black Canyon NP | 2/85-11/93 | | | | BLM - IMPROVE PROTOCOL |
| COLM Colorado NM | 7/81-9/91 | | | | NPS – IMPROVE PROTOCOL |
| COLP Louisiana-Pacific | 7/92-1/97 | | | | NPS - IMPROVE PROTOCOL |
| DEHE Devil's Head Fire Tower Lost Creek WA | 5/94-1/02 | | | | USFS-IMPROVE PROTOCOL |
| DINO Dinosaur NM | 9/79-2/81<br>6/85-9/91 | | | | NPS-IMPROVE PROTOCOL |
| DOPA Douglas Pass | | | | 9/03-1/06 | Colorado-IMPROVE Look Alike |
| EANE Eagle's Nest WA | 6/93-9/00 | | | | USFS-IMPROVE PROTOCOL |
| GRSA Great Sand Dunes NP | 7/87-4/95 | | | 5/88-present | NPS - IMPROVE |
| LAGA La Garita WA | 9/97-10/01 | | | | USFS-IMPROVE PROTOCOL |

1 IMPROVE Protocol sites are operated using the same equipment and procedures as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by the sponsoring federal land management agency or state. Sites are operated by the NPS, BLM, or the USFS.

| SITE | CAMERA | TRANSMIS-SOMETER | NEPHELO-METER | IMPROVE PARTICULATE MONITORING | SITE TYPE[1] |
|---|---|---|---|---|---|
| MEVE Mesa Verde NP | 9/79-4/95 | 9/88-7/93 | | 3/88-present | NPS - IMPROVE |
| MOMA Mt. Massive WA | 7/97-11/01 | | | | USFS - IMPROVE |
| MOZI Mt. Zirkel WA | 10/90-present (on Storm Peak) | | 12/93-present | 12/93-present | USFS - IMPROVE |
| RICR Ripple Creek Pass Flat Tops WA | | | | 12/02-present | Shell Oil-IMPROVE Look Alike |
| ROMO Rocky Mtn. NP | 10/85-1/95 | 12/87-10/06 | | 10/87-present | NPS - IMPROVE |
| SHMI Shamrock Mines Weminuche WA | 11/05-present | | | | USFS – IMPROVE PROTOCOL |
| WEEL West Elk WA | 7/92-11/96 | | | | USFS - IMPROVE PROTOCOL |
| WEMI Weminuche WA | 7/86-8/93 | | | 3/88-present | USFS - IMPROVE |
| WHRI/ MABE Maroon Bells/ Snowmass WA | 12/91-present | | | 7/93-9/99 (channel A only)<br>9/99- (full IMPROVE) | USFS – IMPROVE PROTOCOL<br>USFS – IMPROVE |

In 2003, two temporary sites were installed in Western Colorado. The sites use IMPROVE protocols and equipment but are unable to utilize one of the analytical laboratories under contract

to the long-term sites. As such, these temporary sites are known as IMPROVE Look Alike sites. One is at the north end of the Flat Tops Wilderness at Ripple Creek Pass and is funded by Shell Exploration and Production Company. The other was to the west of the first site nearly on the border with Utah at Douglas Pass. It has been discontinued. This site was funded by the Colorado Governor's Office of Energy Management and Conservation. The sites were installed and operated by a consulting firm, Air Sciences, Incorporated. The Division has provided technical support and advice as needed. As data are processed from these sites, they are uploaded to the VIEWS site annually. Data analysis from these sites are included in the Regional Haze SIP Technical Support Documents (TSDs).

A new IMPROVE protocol site has recently (Fall 2005) been added to the network within Colorado by the USFS. The Shamrock Mines site near Vallecito and the Weminuche Wilderness is intended to supplement the existing Weminuche Wilderness site. Shamrock Mines is at a much lower altitude than the current site. NOx and ozone are also monitored at the new site. The USFS is concerned with the cumulative impacts of oil and gas development in the 4-corners region and believes the new location will better capture pollutants in the area.

For IMPROVE and IMPROVE Protocol sites in Colorado the camera, transmissometer, and nephelometer based data are collected, analyzed, and archived by Air Resource Specialists, Inc. (ARS), the contractor to IMPROVE, NPS, USFS and BLM for optical data. The particle data are collected, analyzed and archived by the University of California at Davis, the contractor to IMPROVE, NPS, USFS and BLM for particle measurements. For the IMPROVE Look Alike sites, Air Sciences, Inc. operates the sites and uses the same lab except for the University of California at Davis. Instead, RTI, Inc. is utilized. For all sites, the raw data may be downloaded from the IMPROVE or VIEWS web sites.

**c. Site-By-Site Data Summaries.**

Due to the extensive data analyses and displays within the Technical Support Documents and other sections of the Regional Haze SIP submittal, this LTS Review's focus is solely on trends at sites with more than 3 years of data. Trends in the haze index, known as deciview (dv) are provided for both the Best 20% days each year and Worst 20% days each year. These plots have been copied from the VIEWS web site. An additional focus is on the data since the last LTS Review in 2004.

**(i). Mesa Verde National Park**.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Mesa Verde National Park. Figure 1 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no particular trend but are not degrading. The Worst Days appear to have an overall steady increase in impairment beginning in 1992 through 2000. 2001 is the lowest year on record and 2002/2003 are the worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 2 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 2 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mesa Verde. Nitrate shows an increasing trend beginning around 1999 and continuing through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend over the years.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mesa Verde with no particular trend but demonstrates more variability beginning in 2000.

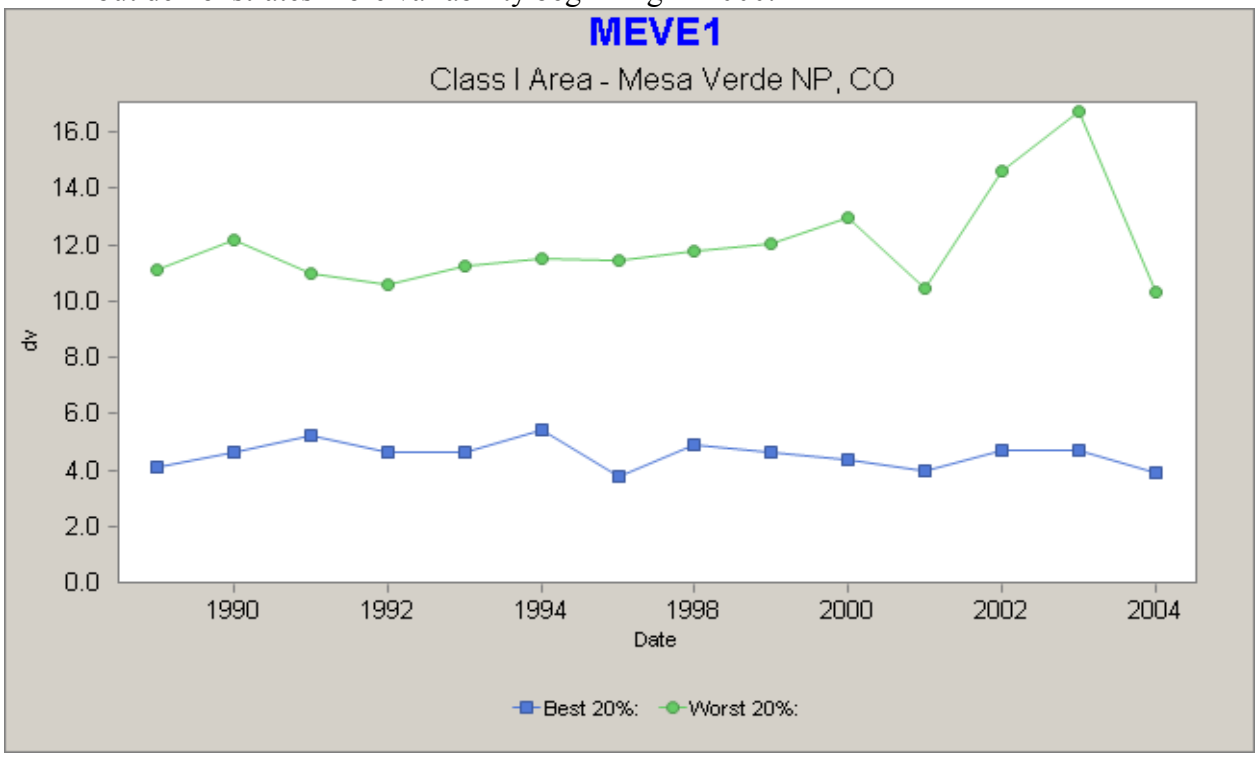



**Figure 1: Mesa Verde National Park, Best and Worst Days, 1989 through 2004**

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Mesa Verde, it starts fairly high early in the record then drops and begins a slow increase until 2000. Beginning in 2000, there is a period of "ups and downs" corresponding to the period of drought and wildfire in the West. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Mesa Verde NP.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values early in the record at the Park with increases corresponding to the drought period.

The influence of drought and related emissions from wildfire and dust events is evident. Figure 3 examines precipitation at Mesa Verde National Park from 1990-1997 versus 1998-2004. Average precipitation is around 6 inches lower in the more recent period and several years (1999-2002) have annual averages between 11.6 and 13.8 inches, reflecting the profound drought in the area.

**(ii). Weminuche Wilderness Area.**

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Weminuche Wilderness Area. Figure 5 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show no degradation and a steady trend toward less impairment. The Worst Days appear to have a slight increase in impairment beginning in 1993 through 2000. 2001 is the lowest year on record and 2002/2003 are the 3rd and 4th worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 6 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 6 by pollutant shows that:

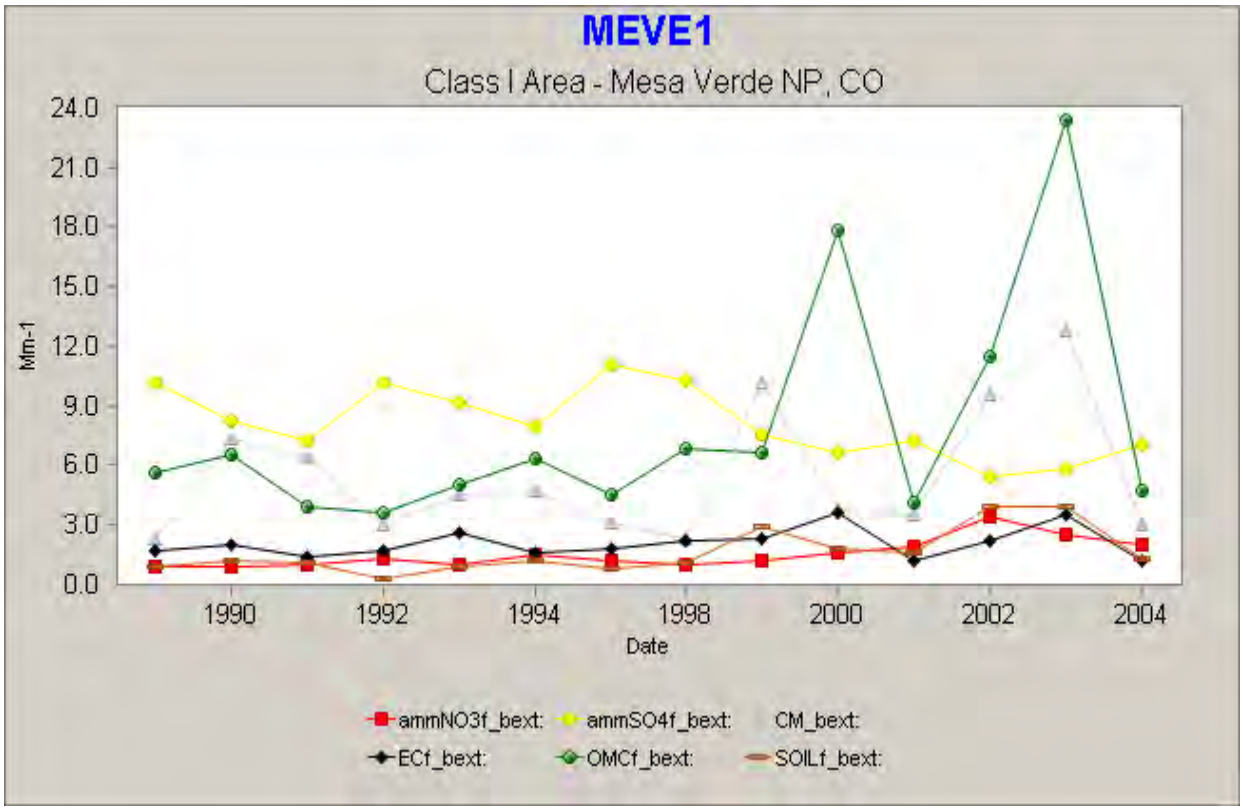



**Figure 2: Mesa Verde National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004**

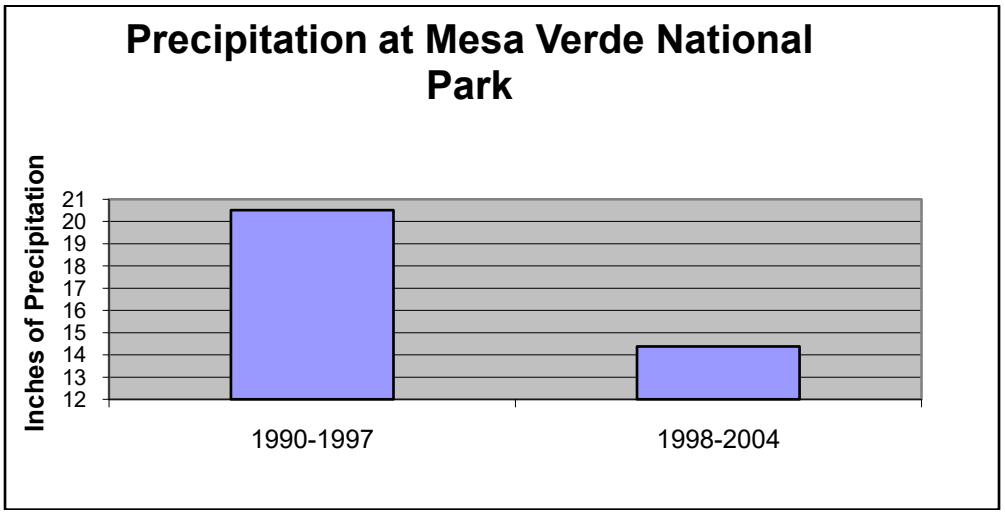



**Figure 3: Precipitation At Mesa Verde National Park, 1990-1997 vs 1998-2004**

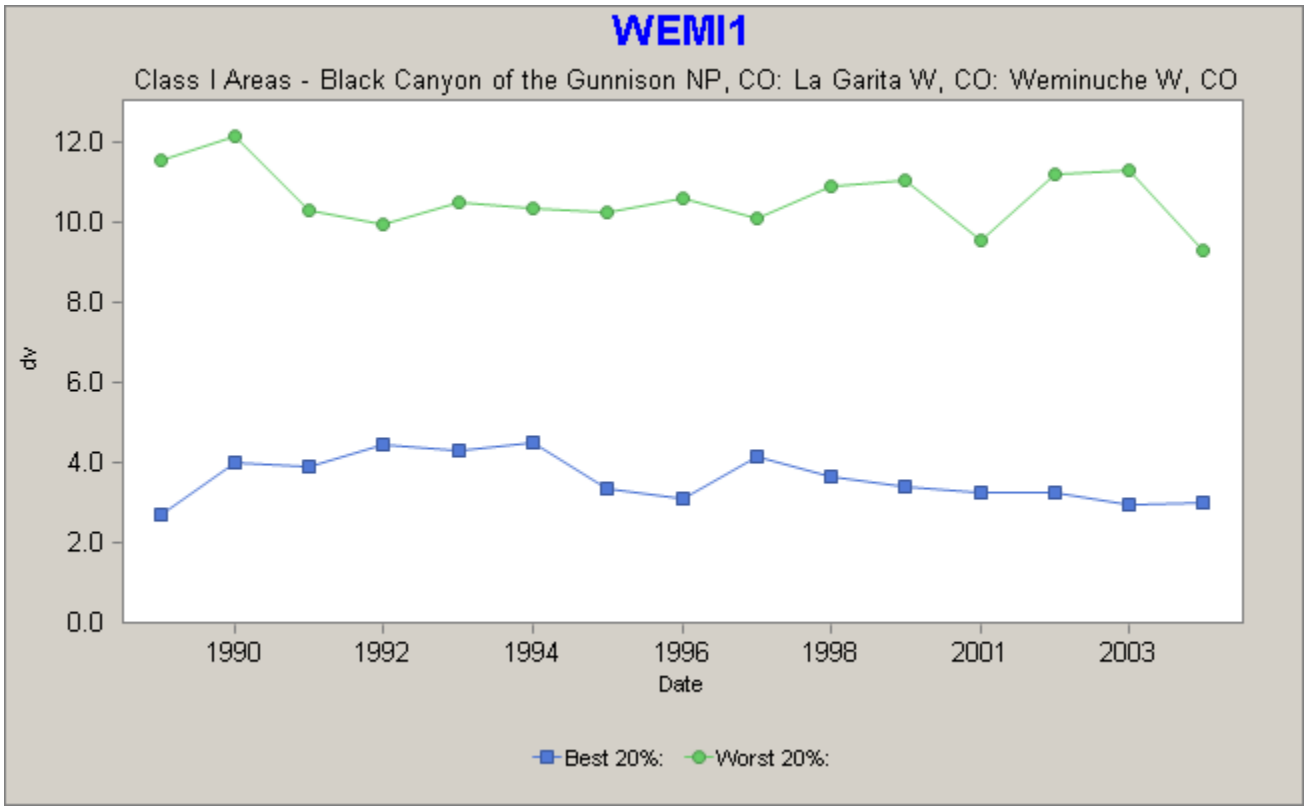



**Figure 5: Weminuche Wilderness Area, Best and Worst Days 1989 through 2004**

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Weminuche. Nitrate shows an increasing trend beginning around 1997 and continuing through 2003. The 2004 value is less than recent years and is similar to what was measured in 2001.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a moderate contributor at Weminuche with a slight shift to lower values beginning in 1997.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Weminuche, it starts fairly high early in the record then drops and begins a slow increase until 2001. Beginning in 2001, there is a period of large variability corresponding to the period of drought and wildfire in the West and particular fires near and in the Weminuche Wilderness. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Weminuche.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period.

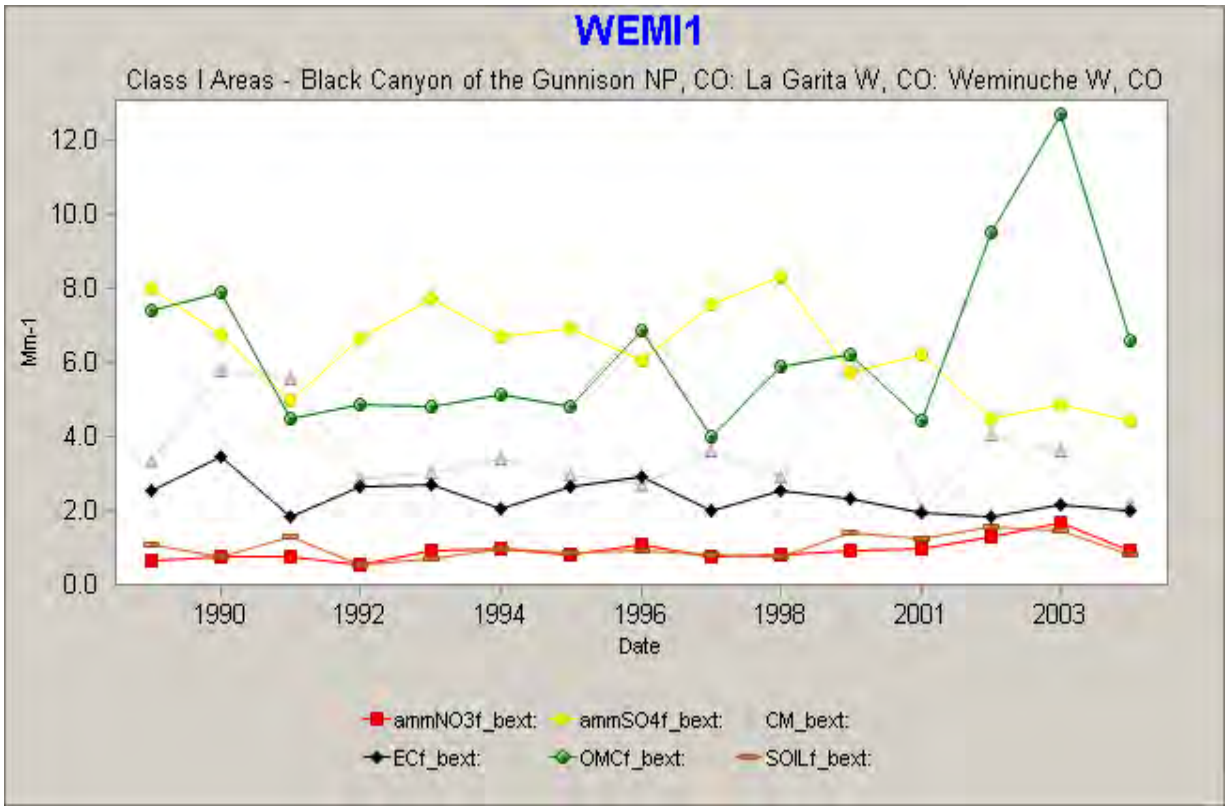



**Figure 6: Weminuche Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004**

**(iii). Great Sand Dunes National Park.**

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Great Sand Dunes National Park. Figure 7 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show a little change and overall no degradation since 1999. The Worst Days appear to have a slight increase in impairment beginning in 1996 through 2000. 2001 is among the lowest years on record, followed by 2002: the highest on record. 2003 is the 4th worst and 2004 again returns to low values similar to 2001 and among the lowest on record. To explore these trends and the recent extreme variability further, Figure 8 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 8 by pollutant shows that:

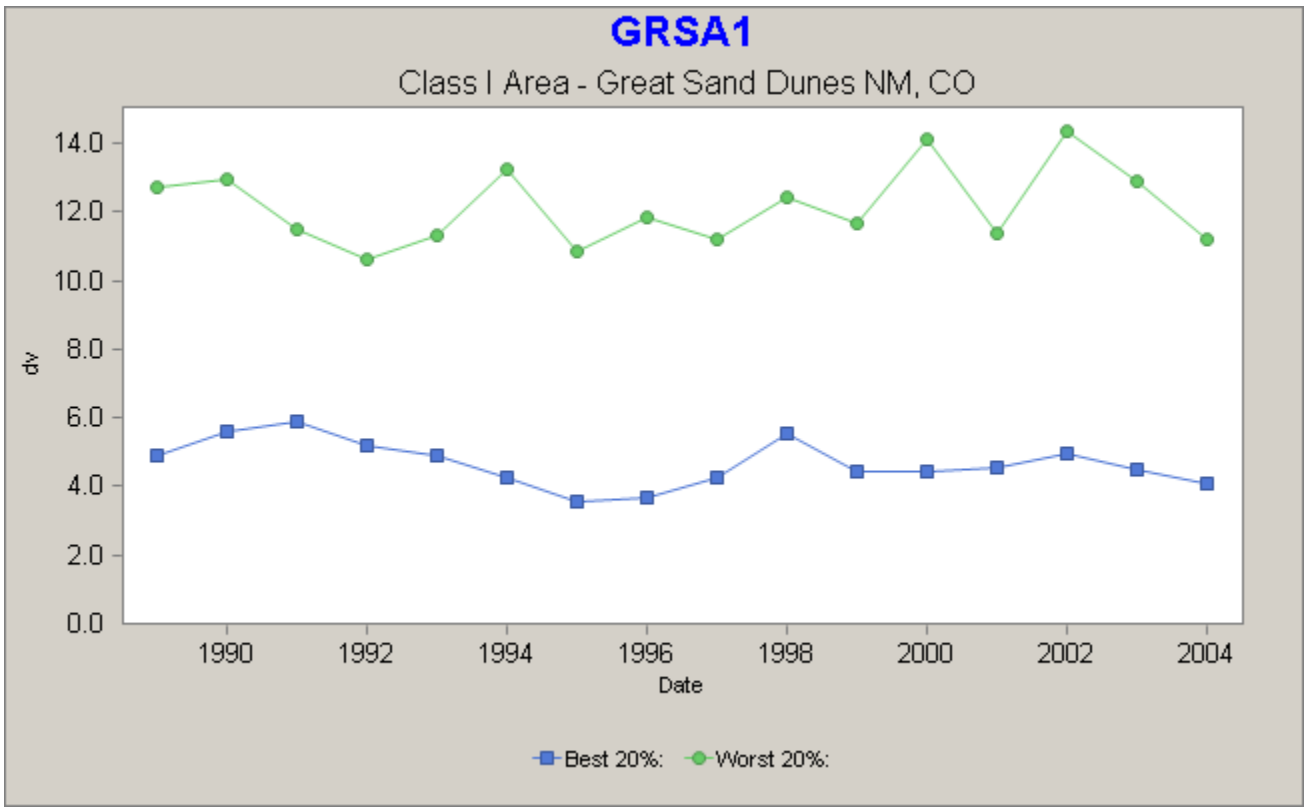



**Figure 7: Great Sand Dunes National Park, Best and Worst Days 1989 through 2004**

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Great Sand Dunes. Nitrate shows a slight increasing trend beginning around 2000 and continuing through 2004, with a dramatic exception in 2003 (among the lowest values on record). The 2004 value is the highest on record.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a major contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Coarse mass shows a huge amount of variability

over its record with the "ups and downs" tracking closely with Organic Carbon in recent years.

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Great Sand Dunes NP with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Great Sand Dunes, it begins an "up and down" pattern in 1995 thru 2003. The pattern is broken by 2004 as its value continues in 2003's declining direction.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period. Fine soil, coarse mass and organic carbon emerge in recent years as the most important contributors to impairment and variability in impairment at Sand Dunes.

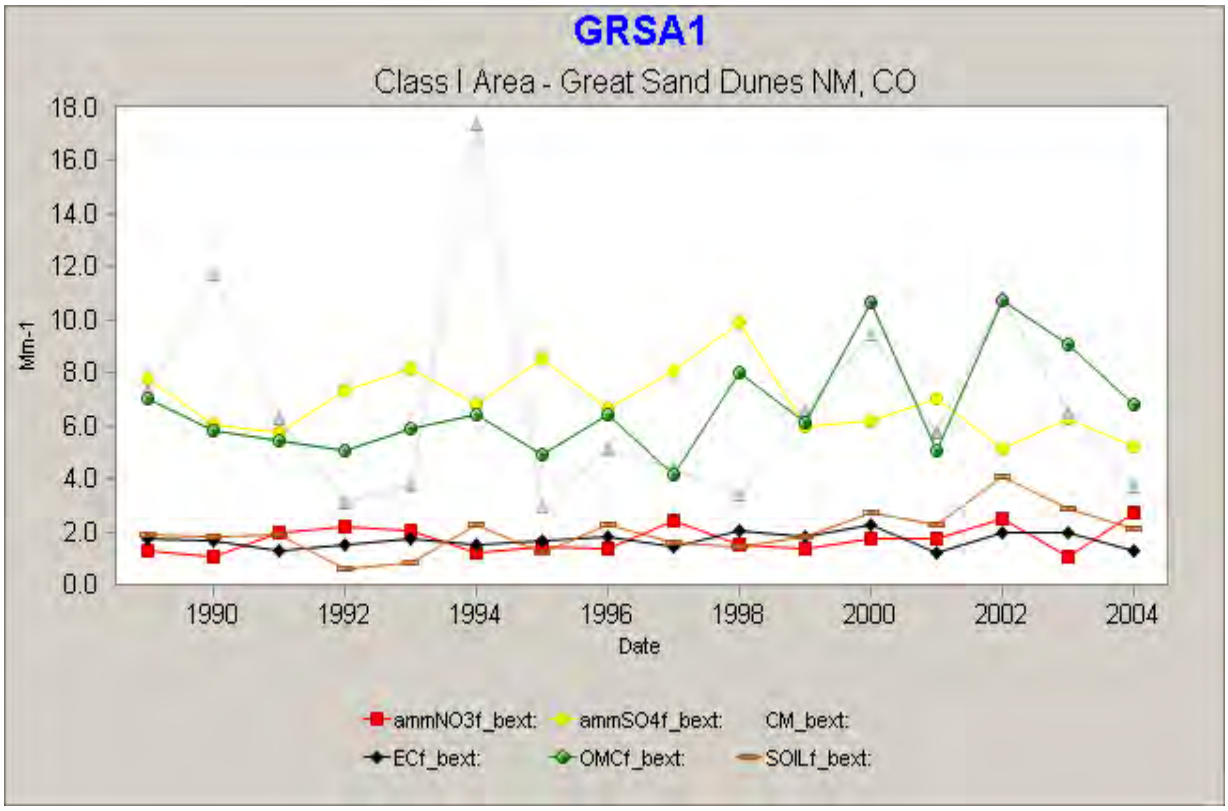



**Figure 8: Great Sand Dunes National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004**

**(iv). White River National Forest - Maroon Bells/Snowmass Wilderness.**

Processed IMPROVE Sampler data are available beginning in 2001 through 2004 at the White River site. Figure 9 presents annual average deciview for the best and worst days for each year of available data at the site. All other IMPROVE sites in Colorado have much longer data records, in most cases over 15 years. However, the White River site was installed during 2000, with the first complete data year in 2001. Based on the

four years of processed data, White River is Colorado's least impaired site compared to other IMPROVE locations in the state.

The Best Days show a no degradation trend over the four years of data. The Worst Days spike-up in 2002 but return to the 2001 value in 2003 and decline further in 2004. To explore these trends, Figure 10 contains a speciated look at the Worst Days from 1981 through 2004. A qualitative summary of Figure 10 by pollutant shows that:

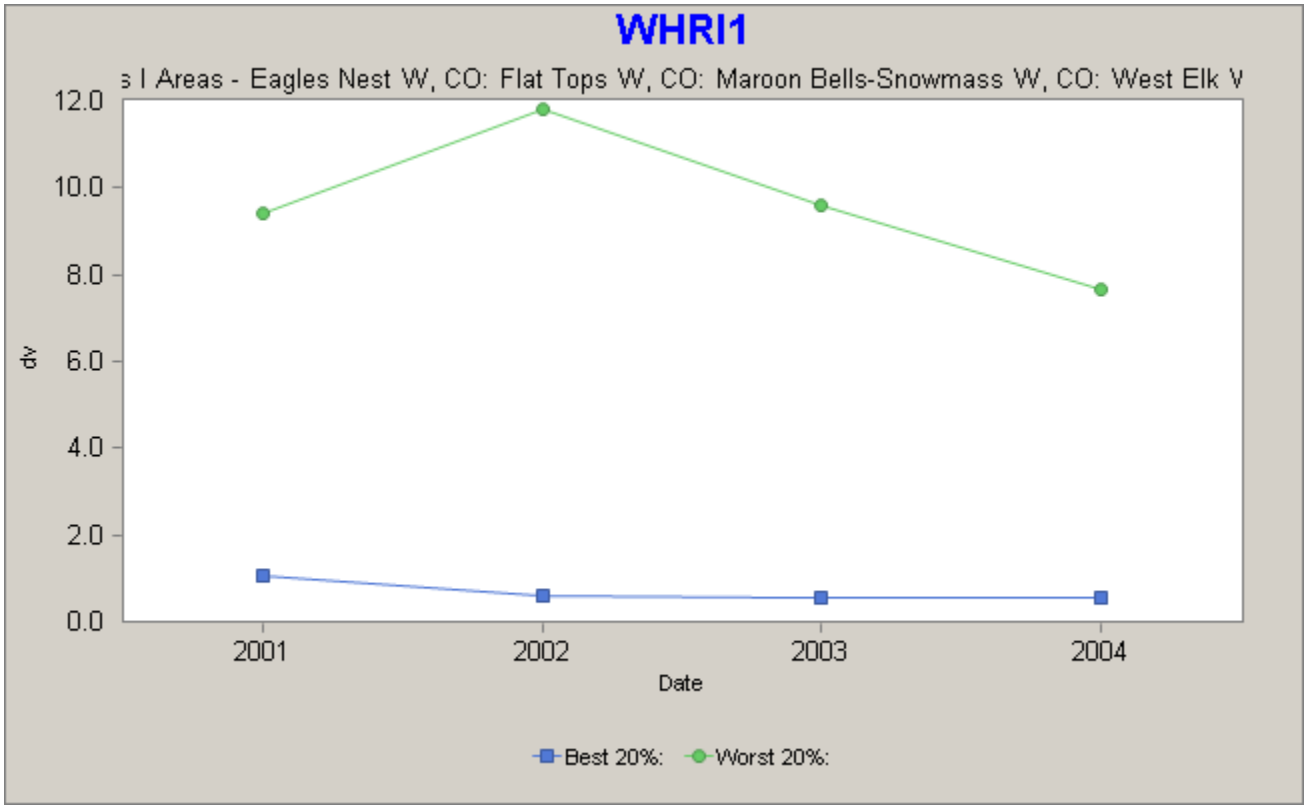



**Figure 9: White River National Forest, Best and Worst Days 2001 through 2004**

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at the White River site. Nitrate shows a slight decreasing trend through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a moderate contributor at the White River site. Sulfate shows an overall decreasing trend.
- CM_bext (coarse mass extinction) is fairly moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to other sites in Colorado examined previously, there has been little relative variability in course mass and it declined in 2003 and 2004.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at the wilderness areas represented by the White River site and has had only a small amount of variability in the four years monitored.

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Organic carbon is a moderate contributor at White River, with the exception of 2002 when it spiked (likely due to upwind wildfire) and influenced impairment at the site more than the sum of the other pollutants combined.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

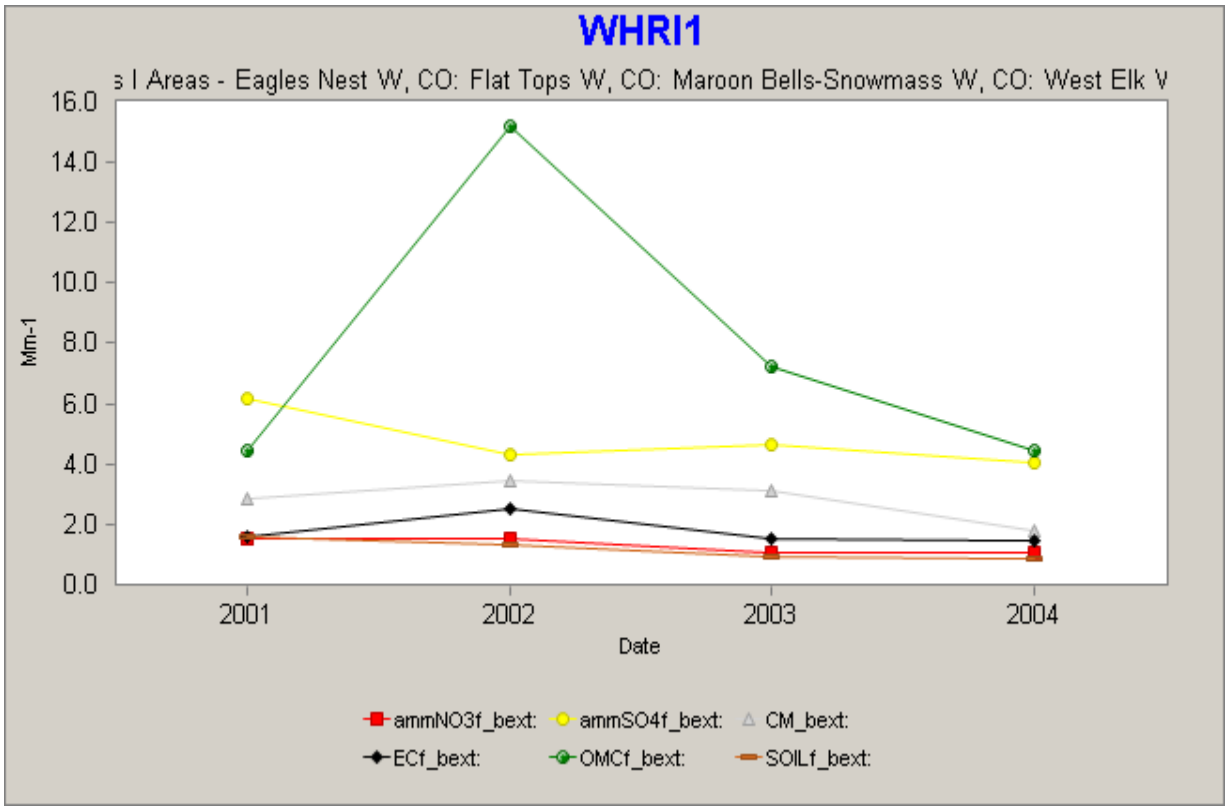



**Figure 10: White River National Forest, Annual Extinction Values by Aerosol Species, Worst Days 2001 through 2004**

**(v). Mt Zirkel Wilderness Area.**

Processed IMPROVE Sampler data are available beginning in 1995 through 2004 at Mt. Zirkel Wilderness Area. Figure 11 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show a no degradation trend over the 9 years of data (2000 was incomplete) with a fairly dramatic decline in impairment in recent years. The Worst Days do not exhibit any obvious trend; however, 2004 was the lowest on record. To explore these data further, Figure 12 contains a speciated look at the Worst Days from 1995 through 2004. A qualitative summary of Figure 12 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mt. Zirkel Wilderness Area. In recent years nitrate has increased and appears to be a moderate level contributor.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to the more southern sites, coarse mass at Mt. Zirkel shows little variability over its record and an overall declining trend.

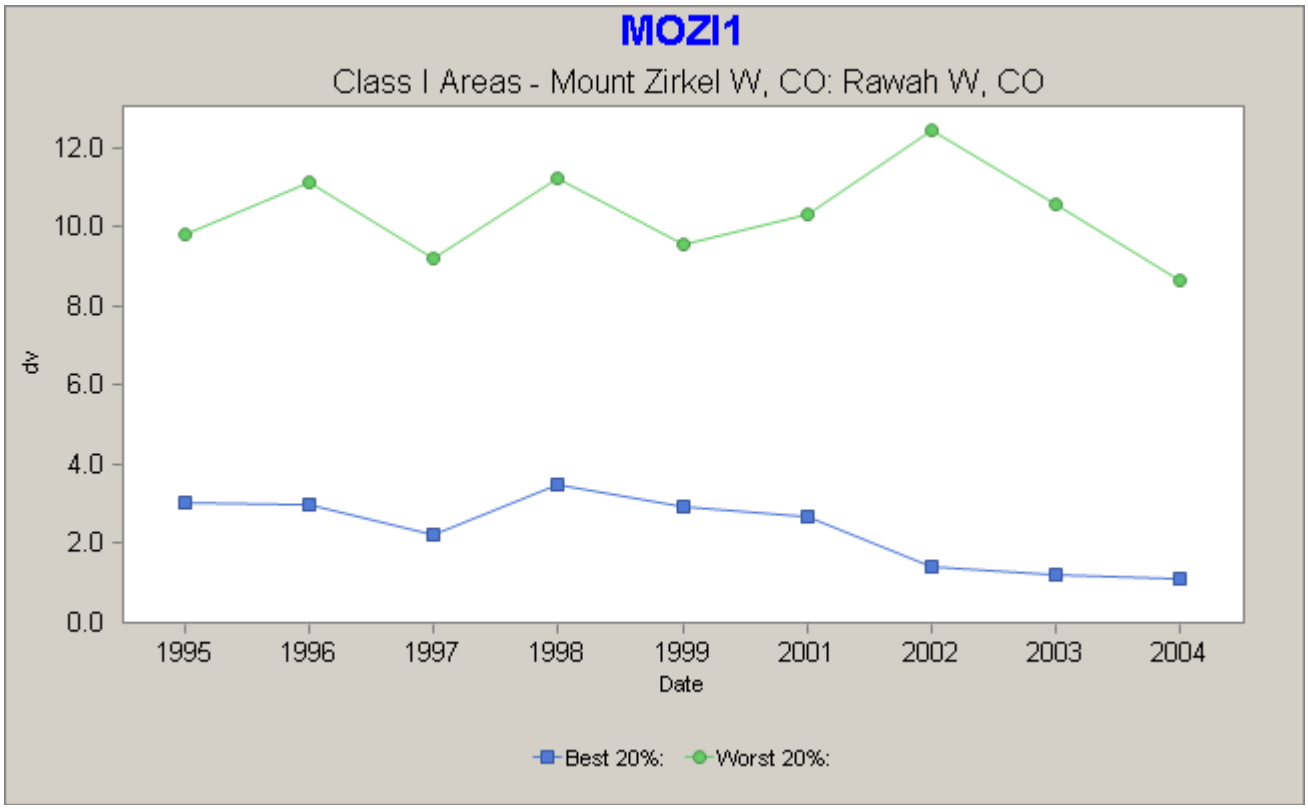



**Figure 11: Mt. Zirkel Wilderness Area, Best and Worst Days 1995 through 2004**

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mt. Zirkel Wilderness Area with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire) and a major contributor to impairment at this site. Over the period of monitoring at Mt. Zirkel Wilderness, organic carbon exhibits considerable variability and, similar to most other Colorado sites, had large annual worst day values for 2002 and 2003.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

**(vi). Rocky Mountain National Park.**

Processed IMPROVE Sampler data are available beginning in 1991 through 2004 at Rocky Mountain National Park. Figure 13 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no degradation over time and a trend toward less impairment. The most recent years are the cleanest on record. The Worst Days reflect the drought and shift up from 2000 through 2003. To explore these trends and the recent increase on the Worst Days further, Figure 14 contains a speciated look at the Worst Days from 1991 through 2004. A qualitative

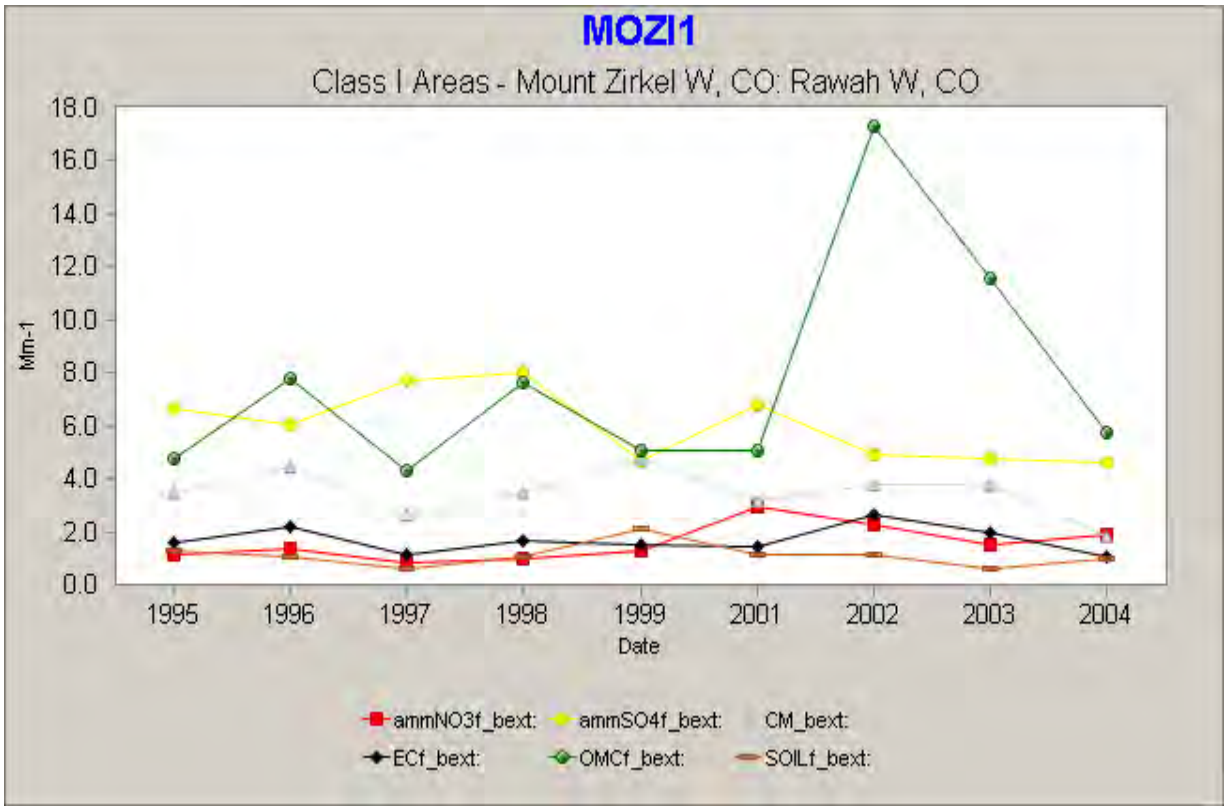



**Figure 12: Mt. Zirkel Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1995 through 2004**

summary of Figure 14 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and shifts from a moderate contributor to visibility impairment at Rocky to a major contributor in 2001 and 2002. Values for 2003 and 2004 drop to more typical levels. Nitrate shows a decreasing trend from the beginning of the record through 2000 then the two-year spike occurs. Rocky Mountain National Park's nitrate levels are higher overall than other IMPROVE sites in Colorado. The two-year spike is unusual given that nitrate is largely an anthropogenic pollutant.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. In contrast with other IMPROVE sites in Colorado, sulfate does not demonstrate an obvious declining trend over the data record. However, considering the period 1999 through 2004, there are 4 of the 5 lowest values in the data record. Similar to what was seen for nitrate, the sulfate spike in 2001 and 2002 may need further exploration.

- CM_bext (coarse mass extinction) is a moderate contributor. In 2000, it spiked and for that single year it was a major contributor, along with organic carbon. Coarse mass emissions mostly consist of natural sources (e.g., wind blown dust). Coarse mass does not reveal an obvious trend over the record and there is a lesser reflection, compared to

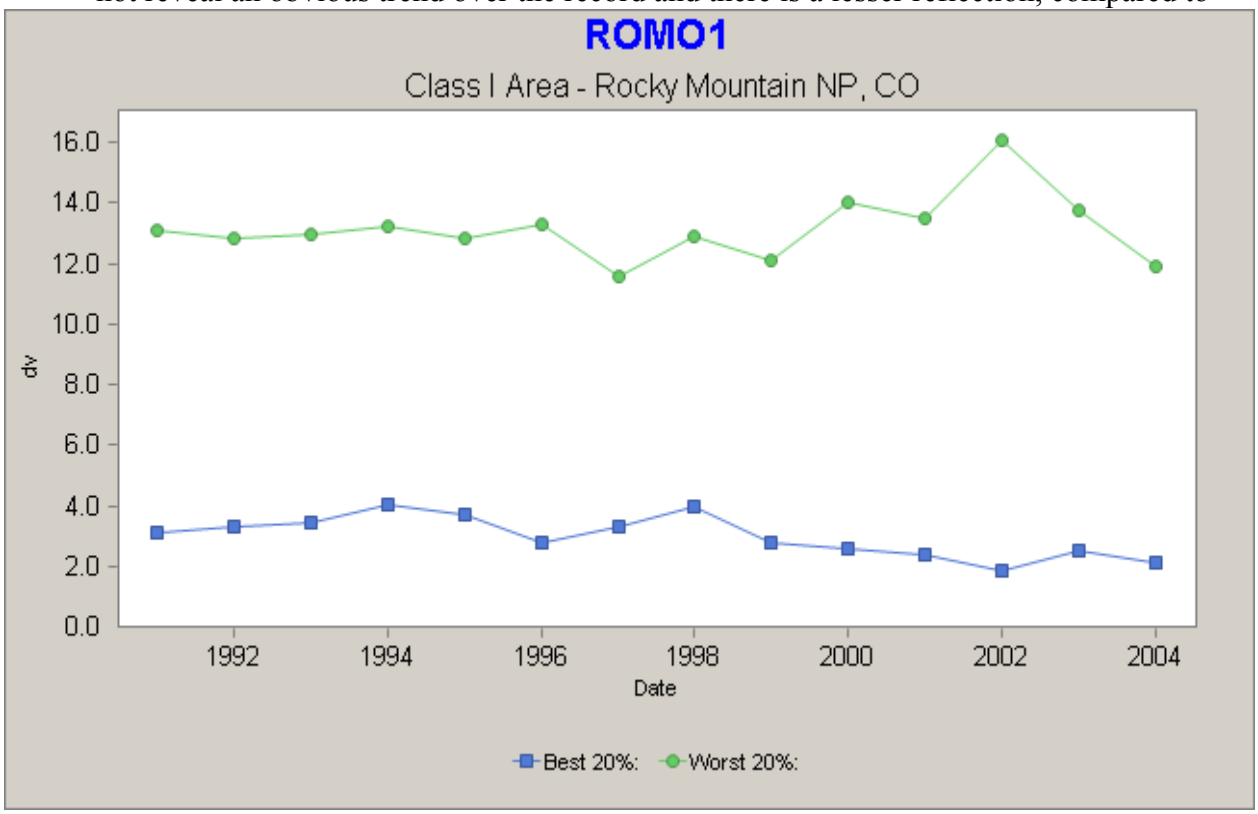



**Figure 13: Rocky Mountain National Park, Best and Worst Days 1991 through 2004**

many other sites in Colorado, of the drought in recent years.

- ECf_bext (elemental carbon extinction) is a both an anthropogenic (e.g., diesel emissions) and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Rocky Mountain NP with no particular trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Rocky Mountain National Park, the "ups and downs" seen at other sites also have occurred at Rocky as well as the large values during the peak drought years.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with low values throughout the record at the Park.

In order to explore further the unusual nitrate and sulfate levels in 2001 and 2002, additional plots are presented below from the VIEWS website. They are the 2000, 2001 and 2002 annual composition plots for Rocky Mountain National Park. Each stacked bar represents a 24-hour sample. Each bar component is one of the species listed on the plot legend. The "W" over a bar means that sample is among the worst 20% impaired during that year. A "B" over a bar indicates that sample is in the 20% best visibility days during that year. Figure 15 is 2000 data.

This is a fairly typical year for sulfate and nitrate at Rocky. There are no combined sulfate and nitrate episodes above 20/Mm-1 of extinction. Figure 16 is 2001 data. There are 9 sample days with combined sulfate and nitrate above 20/Mm-1. Figure 17 is 2002 data. There appear to be 7 or 8

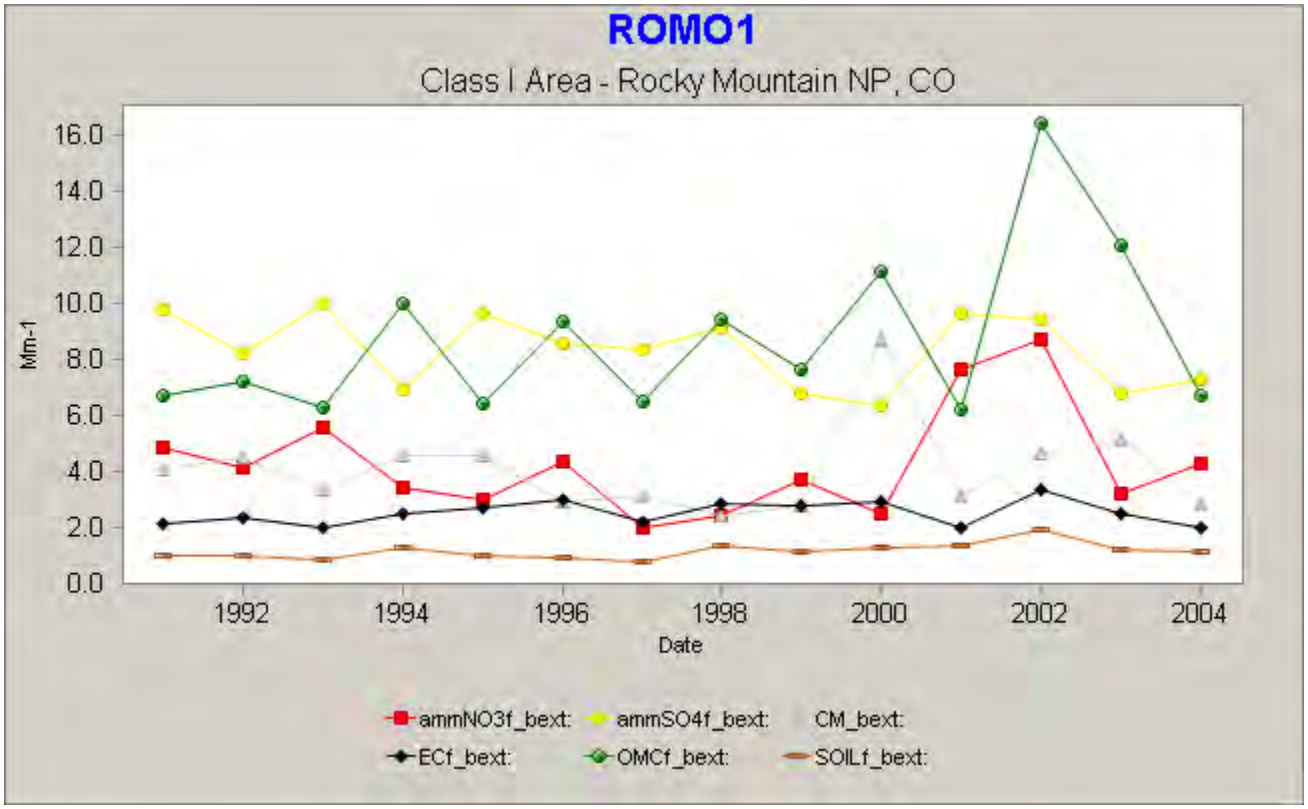



**Figure 14: Rocky Mountain National Park, Annual Extinction Values by Aerosol Species, Worst Days 1991 through 2004**

such days in 2002. It is important to note that these episodes, with 1 or 2 minor exceptions, do not occur when other pollutants are also peaking. The Division is hopeful that results from the ROMANS study, conducted by the National Park Service to examine nitrogen and sulfate emissions and precursors at Rocky Mountain National Park, will provide some insight about the sources and meteorological conditions that occurred in 2001 and 2002 that led to the 7-9 peaks of sulfate and nitrate per year. For more information about the ROMANS study see **http://www.cira.colostate.edu/publications/newsletter/fall2006.pdf**

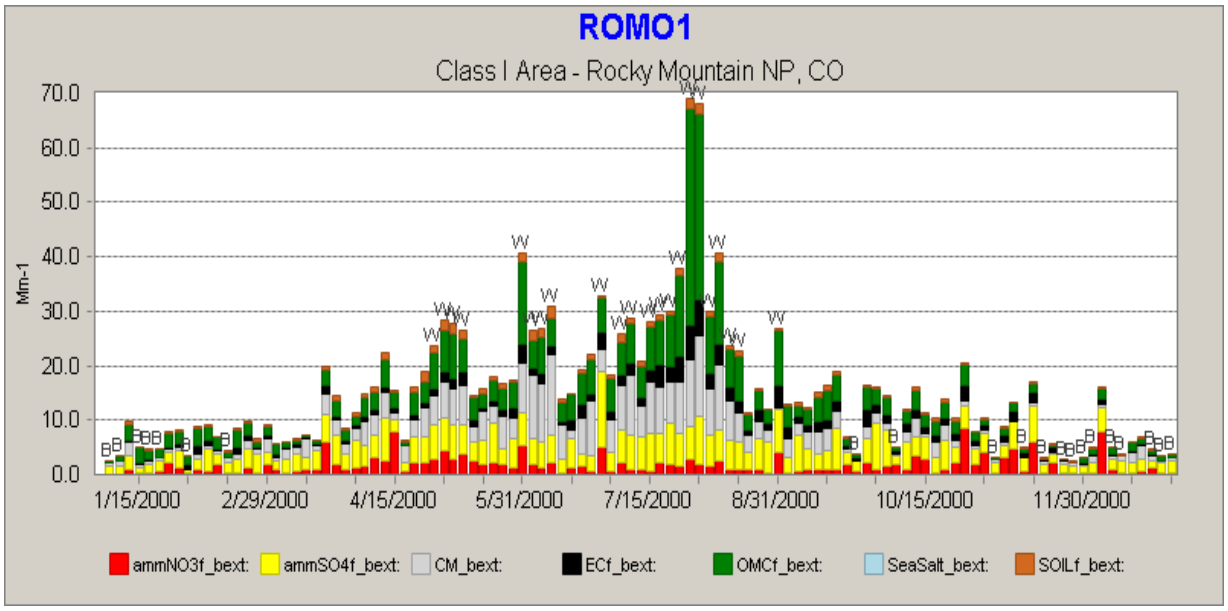



**Figure 15: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2000**

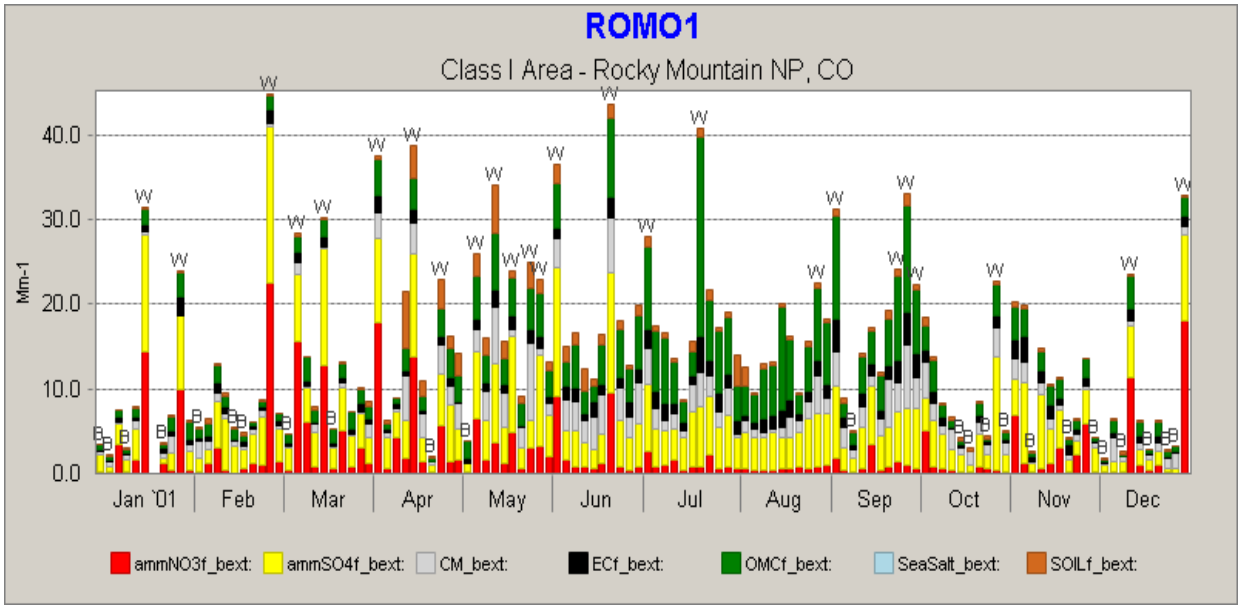



**Figure 16: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2001**

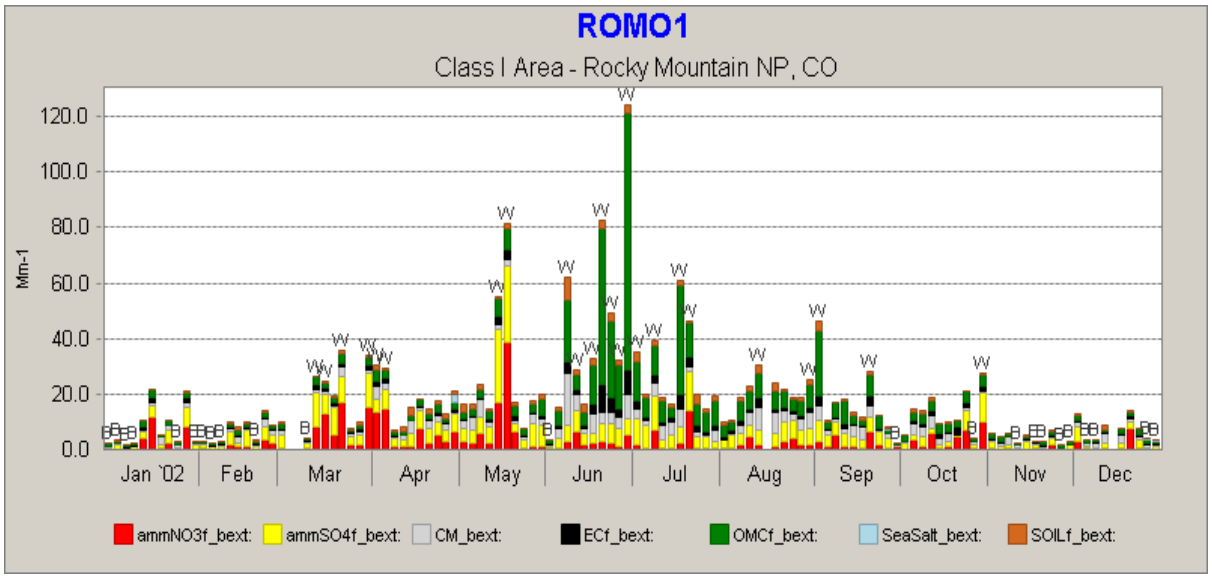



**Figure 17: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2002**

**d. Overall Conclusions.**

Colorado has among the best visibility in the country at its Class I areas and throughout other scenic and pristine parts of the State. However, on an episodic basis visibility can become impaired at all sites monitored.

Visibility on the best days is not degrading over time at any site in Colorado. This is good and important news as protecting the cleanest days is a critical aspect of the Class I visibility protection program.

Visibility on the worst days is a more complex assessment. Mesa Verde NP shows a slow and steady increase in impairment over time. Weminuche and Great Sand Dunes show a very slight increase in impairment. Rocky Mountain and Mt. Zirkel show little apparent trend. At all these sites the most recent years of complete data have large variation from year-to-year driven largely by the sustained drought in the West. In addition to direct impacts from the drought, fewer precipitation events equate to less of a potential for natural removal mechanisms (i.e., rain and snow storms) scrubbing particles out of the air. The data record for White River is too short to draw conclusions at this time regarding trends.

## 4. ADDITIONAL MEASURES, INCLUDING SIP REVISIONS, THAT MAY BE NECESSARY TO ENSURE REASONABLE PROGRESS TOWARD THE NATIONAL GOAL.

Substantive LTS SIP revisions occurred in August 1996, April 1997, and April 2001. The 2002 SIP revision was to update outdated language and create a better overall organization of the LTS portion of the SIP. A minor update occurred in 2004. The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However,

once again, small updates and edits are proposed in order that this part of the SIP does not become outdated.

## 5. THE PROGRESS ACHIEVED IN IMPLEMENTING BART AND MEETING OTHER SCHEDULES SET FORTH IN THE LONG-TERM STRATEGY.

*Hayden.* Emission limitations and schedules for Hayden Generating Station were adopted into the SIP on August 15, 1996 based on the Hayden Consent Decree. By terms of the Decree, Hayden Station must provide progress reports to the State concerning construction of new equipment and compliance with new emission limitations. The particulate and $SO_2$ control equipment for Units 1 & 2 have been installed and are operating. All schedules in both the Decree and in the SIP regarding Hayden were met, some up to six months ahead of deadlines in the SIP and Consent Decree. Both units were in compliance for all pollutants by November 16, 1999. The emission limits and reporting requirements have been integrated into Hayden's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2001. Since then Hayden has continued to operate the facility within its emission limits and has remained in compliance.

*Craig.* Emission limitations and schedules for Units 1 and 2 of the Craig Station were adopted into the SIP on April 19, 2001 based on the Craig Consent Decree. By the terms of the SIP, progress reports must be provided to the State.

Unit 1's tie-in with its new equipment began on September 13, 2003 and completion of PM, NOx and $SO_2$ upgrades were finished by December 19, 2003. Testing of the NOx upgrades continued through the end of $4^{th}$ quarter 2003. $SO_2$ removal has consistently been above 90% since mid-December 2003 (limit is 90%). The NOx limit is 0.30 lbs/Mmbtu annual average and the end of 2005 actual average was 0.279 lbs/Mmbtu.

Unit 2's tie-in began on March 13, 2004. The compliance period began on October 1, 2004 for all subject pollutants. $SO_2$ emissions from Unit 2 have also consistently achieved better than 90% removal and the NOx annual average has been below the required 0.30 lbs/Mmbtu.

The emission limits and reporting requirements have been integrated into Craig's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2005. Since then Craig has continued to operate the facility within its emission limits and has remained in compliance.

## 6. THE IMPACT OF ANY EXEMPTION FROM BART.

The Division has not made a reasonable attribution decision. The need for a BART analysis has not been triggered, therefore, exemptions were neither requested nor granted.

## 7. THE NEED FOR BART TO REMEDY EXISTING IMPAIRMENT IN AN INTEGRAL VISTA DECLARED SINCE PLAN APPROVAL.

There have been no integral vistas listed by either the federal land managers or the State since the plan was approved. Therefore, a discussion on the need for BART in such integral vistas is not necessary.

## IV. CONSULTATION WITH FEDERAL LAND MANAGERS

The Division is required by federal and state law to provide at least 60 days to consult with the federal land managers during periodic reviews of the LTS. The Division is sending this report to the USFS and NPS at the time of the request for hearing before the Air Quality Control Commission. These agencies are the managers of all of Colorado's Class I areas.

## V. ENDNOTES AND REFERENCES


1. Letter to Honorable Roy Romer, Governor of Colorado, from Elizabeth Estill, Regional Forester, U.S. Forest Service Rocky Mountain Region, July 14, 1993.

2. "Revision of Colorado's State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements," adopted by the Colorado Air Quality Control Commission, April 19, 2001.

3. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements," 66 Federal Register, 35374.

4 . Watson, J.G. and D. Blumenthal 1996*, Mt. Zirkel Wilderness Area, Reasonable Attribution Study of Visibility Impairment; Volume II: Results of Data Analysis and Modeling, Part 1 of 2 -- Final Report*; July 1, 1996. Desert Research Institute, University and Community College System of Nevada, 5625 Fox Avenue, Reno, Nevada 89506.

5. In the United States District Court for the District of Colorado, Civil Action No. 93-B-1749, Sierra Club, Plaintiff, vs. Public Service Company of Colorado, Inc., Salt River Project Agricultural Improvement and Power District, and PacifiCorp, Defendants, United States of America and State of Colorado, Plaintiff-Intervenors, Consent Decree, date lodged in Court, May 22, 1996, date entered in Court, August 19, 1996.

6. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements," January 16, 1997, 62 Federal Register, 2305.

7. "Craig Station FGD System Modifications – Analyses of Potential Alternatives, Project Design Basis and Cost Estimates", EPA Contract #'s 68-D7-0001 – Phase # 1-005 & 9X-0264-NALX, dated August 31, 1999.

8. C.R.S. 25-7 Part 10, "Air Quality Related Values – Class I Federal Areas."

9. Letter to Honorable Bill Owens, Governor of Colorado from William P. Yellowtail,

Regional Administrator, EPA Region 8; September, 22, 1999.

10. Letter from Tom L. Thompson, Acting Regional Forester, U.S.D.A. Forest Service, Rocky Mountain Region to Margie Perkins, Director, Colorado Air Pollution Control Division, December 14, 2000.

11. "Regional Haze Regulations," July 1, 1999, 64 Federal Register 35714, (codified at Part 40 Code of Federal Regulations sections 51.308 and 309).

12 . "IMPROVE Data Guide: A Guide to Interpret Data", University of California Davis, August 1995.

# APPENDIX B

## *Regional Haze State Implementation Plan*

***SIP Revision for RAVI Long Term Strategy***

# LONG-TERM STRATEGY REVISION

# OF

# COLORADO'S STATE IMPLEMENTATION PLAN FOR CLASS I AREA VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

**January 2011**

This document is the Phase I Long-Term Strategy (LTS) revision of the State Implementation Plan (SIP) of Colorado"s Class I Visibility Protection Program addressing reasonably attributable visibility impairment (RAVI). The Phase I RAVI LTS review is a separate document and contains background information and the review/report sections as required by EPA and State law.

The state adopted this SIP revision in order to update the LTS. The state adopted an LTS SIP revision in 2007, which was submitted to EPA in 2008 as part of the Regional Haze SIP. For various reasons this submittal was not acted on by EPA. Because of substantial revisions to the Regional Haze SIP in 2010, the state updated, amended and re-adopted this RAVI LTS in 2010. This SIP revision is intended to amend the 2004 LTS portion of the Class I Visibility SIP.

References in this SIP revision to Colorado Air Quality Control Commission Regulation No. 9 (Open Burning, Prescribed Fire, and Permits) are intended only to provide information about the location of various aspects of Colorado"s smoke management program. Regulation No. 9 is neither being submitted for EPA approval nor incorporated into the SIP by reference. It implements Colorado"s program and is not federally required. The State is precluded from submitting this Regulation No. 9 for incorporation into this SIP by C.R.S. 25-7-105.1.

The State of Colorado believes the strategies, activities, and plans outlined below in sections for Existing Impairment, Prevention of Future Impairment, Smoke Management, and Consultation and Communication with Federal Land Managers constitute reasonable progress toward the national visibility goal under Phase I. The following Long-Term Strategy addresses the visibility issues that currently face the State of Colorado"s Class I units within the framework of EPA"s Phase I of the visibility protection program. The six factors required by the EPA to be considered in a LTS are embedded within the strategies below and marked with an asterisk for reference.

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## I. EXISTING IMPAIRMENT.

The LTS must have the capability of addressing current and future existing impairment situations as they face the State. Generally, Colorado considers that its Air Quality Control Commission, Regulation No. 3, Part B, §XIV.D ("Existing Impairment") meets this long-term strategy requirement regarding existing major stationary facilities. The State believes that its existing regulations along with the strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal.

### A. Existing Impairment and the Mt. Zirkel Wilderness.

#### 1. The Certification.

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that it was reasonable to believe that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and that local existing stationary sources - the Craig and Hayden power stations - contributed to the problem.

#### 2. Reasonable Progress for the Mt. Zirkel Wilderness.

##### a. Hayden.

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. An agreement, the Hayden Consent Decree, was approved by the federal district court on August 19, 1996. The agreement was between the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice. The Decree was intended to resolve a number of issues, including a Sierra Club lawsuit against the Hayden Station, the needs of the State"s visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC. The State believes that these significant emission reductions will effectively eliminate the visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has indicated that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.

The construction of Hayden"s control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and emission limitations for NOx, $SO_2$, opacity, and particulate matter are being achieved. The relevant emission limitations and monitoring requirements have been moved into the facility"s Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

**b. Craig Generating Station (Yampa Project).**

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999.

After Hayden was resolved in August 1996, the State"s attention turned to Craig Station Units 1 and 2. In addition to the State and the USFS visibility certification, there are other issues concerning the emissions from Yampa Valley power plants. The USFS has strong concerns about local emissions of $SO_2$ and NOx that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. As well, a citizen lawsuit under the Clean Air Act by the Sierra Club directed against Craig Station Units 1 and 2 regarding opacity issues was initiated in late 1996.

After several years of preliminary efforts, studies and workshops, in Fall 1999 the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. The Craig owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. It was approved by the court on March 19, 2001. The State resolved the certification of impairment in relation to Units 1 and 2 of Craig Station by the AQCC adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The Forest Service concluded that all of its concerns related to the Craig Station and the 1993 Certification of Impairment are now resolved. Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, $SO_2$, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility"s Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

**3. BART and Emission Limitations.**

Although BART determinations were not made by the State regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations* for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. These SIP amendments also address the enforceability of Hayden"s and Craig"s emission limitations* (the dates when the facilities must comply with emission limitations and the enforcement structure have been previously adopted into this LTS). Source retirement and replacement* and construction activities* are not required in the SIP or LTS at this time as the Division is unaware of any relevant issues triggering such a necessity. Note that BART determinations under the Regional haze regulations are described in Chapter 6 of the Regional Haze SIP.

**a. Hayden's Emission Limitations.**

The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 are incorporated into this LTS SIP by reference.[1] EPA approved this SIP amendment on January 16, 1997.[2]

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

**b. Craig's Emission Limitations.**

The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 are incorporated into this LTS SIP by reference. The SIP revision was adopted by the AQCC on April 19, 2001[3] and EPA published final approval of the SIP amendment after a public comment period on July 5, 2001.[4]

**4. Monitoring.**

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area. The Division commits to coordinating a monitoring strategy with other agencies and providing periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. The Division worked collaboratively in 2005 with the U. S. Geological Survey to assess the effects of Hayden"s emission reductions. The Division plans on conducting a more comprehensive evaluation of both Craig"s and Hayden"s effects combined. This work should be completed in 2011 after a suitable period of data has been collected.

**B. Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance*.**

There are no outstanding certifications of visibility impairment in Colorado. In addition, the Division has found no evidence that other stationary sources potentially subject to BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA or any other Class I area in Colorado under Phase I of EPA"s visibility program. The USFS certification of visibility impairment at Mt. Zirkel Wilderness Area has been completely resolved. The Division recognizes that regional haze impacts all of Colorado"s Class I areas, including MZWA. The State is prepared to respond to any future certifications as per AQCC Regulation No. 3 § XIV.D.

**C. Ongoing Air Pollution Programs*.**

**1. $PM_{10}$.**

The State of Colorado has attained and maintained the $PM_{10}$ standard in its non-attainment areas throughout the State. $PM_{10}$ attainment and maintenance plans have been approved by EPA for Aspen, Canon City, Denver, Lamar, Pagosa Springs, Steamboat Springs, and Telluride. These various plans contain numerous air pollution control programs that are effectively reducing emissions. The attainment and maintenance of the $PM_{10}$ standard will likely have some small effect (since the standard is only rarely exceeded) on improving visibility in pristine and scenic areas. The Division is committed to maintaining the $PM_{10}$ standard throughout the State.

**2. Urban Haze -- Brown Cloud.**

There is a concern about urban haze in the eastern Front Range urban corridor from the Denver metropolitan area to Fort Collins. This Front Range area is approximately 25-50 miles from Rocky Mountain National Park, a Class I area. The National Park Service, the federal land manager of the Park, has not certified visibility impairment in the Park. Analysis of urban Brown Cloud data in Denver indicates it has improved approximately 28% between 1991 and 2006. The Division will provide periodic trend analysis of the urban Brown Cloud as data

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

permits and continue to provide technical support to efforts to understand and reduce the Brown Cloud.

**3. Emissions in the Four Corners Area.**

The cumulative growth of many minor sources of air pollution, including mobile, area and stationary sources, can slowly lead to degradation of air quality and have visibility impacts. Federal land managers have commented in previous Phase I LTS review/revision cycles regarding concerns about the cumulative emissions and their possible impacts on Class I areas in the southwest portion of Colorado.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning. An executive/steering committee of the Four Corners Task Force that includes representatives from the states of Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables were developed to ensure that all options developed are timely and a final report was issued in November 2007. The report contains analyses of over 100 emission mitigation options that could be utilized in future discussions on reducing emissions in that region.

**4. Plan for Rocky Mountain National Park.**

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

The Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and Early Action Compact/SIP preparation for ozone.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative"s progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a

new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP was approved by the AQCC in April 2007. This plan documented the science of nitrogen deposition and the ecological impacts, presented long-term deposition reduction goals, documented current and potential NOx and ammonia emission reduction options, and established a path for future activities. The plan acknowledges that emission reductions measure targeted at reducing N deposition will likely benefit visibility at RMNP. Colorado intends on analyzing the visibility improvement benefit of any deposition-targeted measure.

One of the commitments made in the 2007 NDRP was to develop a contingency plan that would put in place corrective measures in the event that initial and any subsequent interim deposition goals are not realized. Such a plan was adopted by the Colorado Air Quality Control Commission in June 2010. This contingency plan does not automatically require the implementation of additional emission control measures designed to reduce the deposition of nitrogen in RMNP. Instead, a focused process to develop appropriate responses if and when nitrogen deposition goals are not achieved was adopted.

The Division maintains a website that is a clearinghouse for information related to the Initiative and contains the 2007 NDRP and the 2010 Contingency Plan. Please see:

http://www.cdphe.state.co.us/ap/rmnp.html

## II. PREVENTION OF FUTURE IMPAIRMENT.

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal.

### A. Ongoing Air Pollution Programs*.

#### 1. PSD and NSR.

Generally, Colorado considers that its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities. The State believes that its existing regulations along with the efforts outlined below have together provided for reasonable progress toward the national visibility goal.

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

**a. Modeling.**

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division"s expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division"s web site at: http://www.colorado.gov/airquality/permits.aspx The Division will continue to update its modeling guidance as needed to insure estimated impacts are projected in as technically sound a manner as reasonably possible.

## III. SMOKE MANAGEMENT PRACTICES∗.

The LTS requires that smoke management practices of prescribed burning be addressed.

### A. The Colorado Smoke Management Memorandum of Understanding and AQCC Regulation No 9.

Until 2002, Colorado"s open burning regulation did not specifically address wildland prescribed fire. In this absence, operational understandings evolved over many years between the Division and the users of prescribed fire for grassland and forestland management. Until January 2002, these understandings regarding the details of permitting and reporting of prescribed fire activity were contained in the Colorado Smoke Management Plan and Memorandum of Understanding (MOU). The Colorado Department of Public Health and Environment, the Forest Service, National Park Service, Bureau of Land Management, Fish and Wildlife Service, Air Force Academy, U.S. Army (Fort Carson), U.S. D.O.E. Rocky Flats Field Office, City of Boulder Wildland Fire Department, Colorado Division of Wildlife, and the Colorado State Forest Service were voluntary signatories to the MOU. The AQCC adopted Regulation No. 9 (Open Burning, Prescribed Fire and Permitting) on January 17, 2002. Adopting this regulation includes the voluntary requirements contained in the MOU and applies them to all users of prescribed fire. In addition, the regulation implements Senate Bill 01-214. Overall, Regulation No. 9 is the main vehicle in Colorado for addressing smoke management from general open burning as well as prescribed wildland burning.

### B. SB01-214 and Smoke Management Program Development.

Colorado Senate Bill 01-214 ("Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Thereof") became law in 2001. Regulations implementing it were adopted as part of Regulation No. 9. The statute and implementing regulations require significant users of prescribed fire for grassland and forestland management to conform to the State standard to "minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable in order to minimize the impact or reduce the potential for such impact on both the attainment and maintenance of national ambient air quality standards and achievement of federal and state visibility goals." All significant users are to submit planning documents to the Commission. The regulation asks that planning documents explain the

∗ A factor that must be considered in a LTS SIP revision according to EPA regulation.

decision process and criteria the significant user applies to making choices about fuel treatment alternatives to achieve various land management goals and must demonstrate how the significant user will comply with the State standard. Each planning document will have a public hearing before the AQCC. The AQCC is to review and make recommendations and comments for each planning document. Starting in July 2002, the Division cannot issue burning permits to any significant user of prescribed fire if their plan for an area is not consistent with Commission comments and recommendations. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, Trinchera Ranch, Denver Water Board, Blue Valley Ranch, and Larimer County.

The statute also requires fees. Regulation No. 9 specifies that significant users shall pay fees of $59.98/hour to the Division for review of planning documents. Prescribed fire permitees also pay for the cost of the prescribed fire program based on a cost distribution methodology described in the regulation. The cost of the program is currently about $199,000 annually.

It is the State‟s intention that through this processes described above, the plans and practices of significant users will continue to consider air quality and visibility concerns into their fuel management decision making.

The Division will also continue to annually produce a report on prescribed burning activity and estimated emissions. The report will contain estimates of acres burned, piles burned, and estimated resulting emissions. The Division has annually prepared such reports since 1990.

The regulation, encompassing the new permitting regulation and the implementation of SB01-214, embodies a comprehensive smoke management program with elements relating to review and approval of wildland fuel management planning documents, permitting of specific fires, reporting actual activity, and a fee program regarding open burning. During 2005, the Division certified its program as consistent with EPA‟s *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. Each prescribed fire project is reviewed by Division staff consistent with Regulation No. 9 in the course of establishing smoke permit conditions. Approximately 300-350 wildland fire permit applications are processed each year.

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

## IV. FEDERAL LAND MANAGER CONSULTATION AND COMMUNICATION.

The plans, goals, and comments of the federal land managers are to be addressed during SIP and LTS revisions. Good communication with the federal land managers is important to implementing the LTS and making reasonable progress toward the national goal.

**A. Consultation.**

The federal land managers (FLMs) with Class I areas in Colorado will be given opportunities to comment and provide input during the LTS review and revision process. The Division will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review and to publish the FLM comments and state responses. In accordance with the Regional Haze regulation, the schedule for reviewing and updating this RAVI LTS has been changed from an every three-year period to an every five-year period. The state commits to consult with the FLMs as described above during each five-year review of the LTS.

**B. Monitoring Plan.**

C.R.S. 25-7-212(3)(a) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to "develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan." The agencies have indicated that they have developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA‟s Regional Haze Rule (40CFR51.308(d)(4)) indicates, "The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State… Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments network." The federal agencies‟ monitoring plan relies on this network and ensures that each Class I area in Colorado will have an on-site monitor or an off-site monitor that is representative of visibility in the Class I area. In the 2004 LTS revision, the Division provided letters from the federal land managers and approval letters from the Division. This information is repeated in the 2010 revision and is included here to conform to the requirements of state law to incorporate the monitoring plans in this manner into the SIP.

## V. ENDNOTES AND REFERENCES

1. "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan For Class I Visibility Protection, Part I: Hayden Station Requirements, Section VI. C „Enforceable Parts of the SIP Revision: Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting"", August 15, 1996, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted August 19, 1996 by the Colorado Air Quality Control Commission.

2. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements," January 16, 1997, 62 Federal Register, 2305.

3. "Revision of Colorado"s State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements, Section III „Enforceable Portion of the SIP Revision, Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting", March 13, 2001, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted April 19, 2001 by the Colorado Air Quality Control Commission.

4. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements," 66 Federal Register, 35374.

# APPENDIX C

## *Regional Haze State Implementation Plan*

***Technical Support for the BART Determinations***

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**CEMEX Inc. – Lyons Cement Plant**

## I. Source Description

Owner/Operator: Cemex
Source Type: Portland Cement Manufacturing
Kiln Type: Modified Long-dry Kiln
Review: Best Available Retrofit Technology (BART)

History:

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two potential BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results.




Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex Lyons kiln. The

newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Process Description:

Limestone and other raw materials extracted from the quarry are processed through a primary crusher at the Dowe Flats quarry. The crushed material is transported to the plant on a 2.0 mile belt conveyor system and discharged to a stockpile. The stockpiled material is placed on a belt by means of a front end loader to be processed through a primary crusher, the dryer, and a secondary crusher. The material from the secondary crusher is stored in raw material storage silos.

These storage silos contain silica and iron ore and various quarried raw materials. Material from these storage silos is discharged to weigh belts for the formulation of a desired product. The weigh belts discharge to the raw mill. The raw mill mixes and crushes the blended materials and delivers the homogenized material to storage silos. The homogenized material from the storage silos is delivered to the calciner portion of the kiln. Pulverized coal from the coal mill is fired at the bottom of the flash calciner. The partially calcined material from the calciner then enters the 14 foot 3 inch diameter - 245 foot long rotary kiln, which is located at a slight incline along its horizontal axis. The Cemex kiln process-type is best categorized as a modified long dry kiln. The material travels towards the clinker discharge end where additional pulverized coal is fired for the clinkering process. The clinker is discharged from the kiln into the clinker cooler where it is cooled by air forced through the clinker bed by under grate fans. The cooled clinker is then moved to internal storage in an A-Frame building, or outside storage stockpiles. The stored clinker is the raw material for the finish mill. In the finish mill the clinker is combined with gypsum and other additives, ground to a fine material and stored in product silos. The material in the product silos can be loaded for bulk transport, or sent to a packaging system.

From an overall perspective, the manufacturing process may be viewed as two segments -- clinker production and cement production. The clinker storage allows the two processes to operate at different production rates. During periods of low demand for cement, clinker is accumulated. If cement is in high demand, the clinker production can be supplemented by purchase of clinker from other sources. The overall result is the clinker production can operate at a rather steady rate, while the cement production can operate in response to the current or projected demands.

## II. Source Emissions

There are two BART eligible units at the Cemex facility, the dryer (point 003) and the kiln (point 007). Regulation Number 3 requires sources to submit an Air Pollution Emission Notice (APEN) on each emission point at least every five years. Typically, emission points with low emissions are updated every five years whereas points with higher emissions are updated annually, since fees are assessed on these emissions.

Table 1 lists the APEN reported emissions from the dryer and emission inventory records collected during routine inspections. The 1999 APEN is based on emission factors, whereas the 2003, 2008 and 2009 APENs are based on a stack test. The Division has determined that the 2008 emissions best represents baseline emissions for the dryer since stack test data is considered more reliable then emission factors. Furthermore, the 2008 clinker production is representative of typical operations because it falls within the normal range of the historical average (please see Table 3 below). Consequently, for purposes of this analysis the dryer has baseline emissions of NOx = 10.41 tpy; SO2= 0.89 tpy; and PM10 = 5.12 tpy; based on a recent stack test.

Table 1: Dryer Emissions

| **Dryer SCC - 30500620** | | | | |
|---|---|---|---|---|
| Pollutant | SO2 | NOx | PM10 | CO |
| Allowable Emissions* [tpy] | 36.70 | 13.90 | 22.80 | 57.30 |
| 1999 APEN Emissions [tpy] | 31.10 | 13.30 | 22.20 | 55.40 |
| 2003 APEN Emissions [tpy] | 0.64 | 1.83 | 1.89 | 3.83 |
| 2008 APEN Emissions [tpy] | **0.89** | **10.41** | **5.12** | **2.97** |
| 2009 APEN Emissions [tpy] | 0.37 | 4.27 | 2.10 | 1.22 |
| Baseline [tpy] | **0.89** | **10.41** | **5.12** | **2.97** |
| % Baseline is below Allowable Emissions | -97.8% | -25.1% | -77.5% | -94.8% |
| Baseline Emissions [lbs/ton of Clinker] | 0.004 | 0.04 | 0.02 | 0.01 |

** Current emission limitations are contained in operating permit (95OPBO082)*

Table 2 below lists the emissions from the kiln. The APEN reported SO2, NOx and CO emissions are based on continuous emission monitoring systems (CEMS) and the PM10 emissions are based on periodic stack tests. The Division has determined that the 2002 emissions best represent baseline emissions for the kiln because it corresponds to the high range for SO2 emissions (which can vary significantly due to pyrites in the limestone) and NOx emissions are within the normal historical range along with clinker production which is near the historical average. There is an increase in kiln PM10 emissions starting in 2007 because of a change in CDPHE's APEN reporting policy, which allows for the grouping of common stacks associated with kiln (process group P007) and a change to reporting PM10 emissions based on periodic stack tests rather than the use of emission factors. Consequently, the 2002 PM10 emissions are not the most realistic depiction of anticipated baghouse controls and actual emissions that are listed in more recent kiln (P007) APEN reports.

The EPA BART guidelines suggest that *"the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." See [70 FR 39167]*. There is some variation in the short-term and long-term SO2 emissions depending on the raw material mix, type of clinker produced, and fuel used. Thus, historically there was some flexibility provided in developing the original permit limits to allow of the use of alternative fuels and raw materials, as well as longer averaging periods. The 10-year period (2000-2009) may represent a different kiln operation condition when compared to earlier periods because no petroleum coke was burned in

the kiln despite being permitted to burn such fuel. The Division determined that looking back at kiln operations prior to the year 2000 were not reasonable for purposes of BART. Consequently, the selection of 2002 as the kiln emissions baseline essentially precludes the use of petroleum coke since the use of such fuel would result in SO2 emissions far above 95 tons per year.

The justification for selecting the highest SO2 emission rate over a baseline period is associated with the fact that cement kiln SO2 emissions are not as predictable as a coal-fired boiler (power plant). The sulfur in the coal is sole source of SO2 at a power plant, whereas a cement kiln has two sources, the coal fuel and the sulfide impurities (iron pyrite) in the limestone and other raw materials added to the kiln. Consequently, it is much easier, although still a challenge, to maintain compliance with SO2 limits at coal-fired power plants through careful blending of various coals, or purchasing compliant coal to achieve more consistent sulfur content. Conversely, coal blending for cement kilns only addresses one source of SO2, the other source (the raw materials) varies depending on impurities in the mining deposit and other additives used in clinker production.

Table 2: Kiln Emissions

| **Kiln SCC – 30500606 (120 tons/hour maximum feed rate – 967,680 tons/year dry basis)** | | | | |
|---|---|---|---|---|
| Pollutant | SO2 | NOx | PM10 | CO |
| Allowable Emissions [tpy] | 1,340.0 | 2,649.0 | 133.0 | 396.0 |
| 2000 APEN Emissions [tpy] | 14.4 | 1,729.6 | | |
| 2001 APEN Emissions [tpy] | 18.7 | 1,858.9 | 8.7 | 233.2 |
| 2002 APEN Emissions [tpy] | **95.0** | **1,747.1** | **8.5** | **235.3** |
| 2003 APEN Emissions [tpy] | 48.0 | 1,835.0 | 9.6 | 210.0 |
| 2004 APEN Emissions [tpy] | 26.3 | 1,708.9 | 9.1 | 209.0 |
| 2005 APEN Emissions [tpy] | 27.2 | 1,591.3 | 8.5 | 156.0 |
| 2006 APEN Emissions [tpy] | 44.7 | 2,011.7 | 8.5 | 239.2 |
| 2007 APEN Emissions [tpy] | 65.0 | 1,689.0 | 56.0 | 311.0 |
| 2008 APEN Emissions [tpy] | 55.8 | 1,295.5 | 42.0 | 345.1 |
| 2009 APEN Emissions [tpy] | 15.5 | 495.5 | 17.5 | 102.4 |
| Baseline [tpy] | **95.0** | **1,747.1** | **8.5** | **235.3** |
| % Baseline is below Allowable Emissions | -92.9% | -34.0% | -93.6% | -40.6% |
| Baseline Emissions [lbs/ton of Clinker] | 0.402 | 7.388 | 0.036 | 0.995 |

The average clinker production over the period (2000 – 2008) is 486,031 tons. The year 2009 was excluded from the average as clinker production was well below the average production level.

Table 3: Kiln-Flash Calciner – Historical Emissions

| Year | Actual Clinker Production [tpy] | SO2 [tpy] | SO2 [lbs/ton of Clinker] | NOx [tpy] | NOx [lbs/ton of Clinker] |
|---|---|---|---|---|---|
| 2000 | 539,992 | 14.4 | 0.053 | 1,729.6 | 6.42 |
| 2001 | 508,733 | 18.7 | 0.074 | 1,858.9 | 7.31 |
| **2002** | **472,945** | **95.0** | **0.402** | **1,747.1** | **7.39** |
| 2003 | 516,251 | 48.0 | 0.186 | 1,835.0 | 7.11 |
| 2004 | 472,053 | 26.3 | 0.111 | 1,708.9 | 7.24 |
| 2005 | 440,384 | 27.2 | 0.123 | 1,591.3 | 7.23 |
| 2006 | 466,173 | 44.7 | 0.192 | 2,011.7 | 8.63 |
| 2007 | 479,225 | 65.0 | 0.271 | 1,689.0 | 7.05 |
| 2008 | 478,520 | 55.8 | 0.233 | 1,295.5 | 5.41 |
| 2009 | 185,076 | 15.5 | 0.167 | 495.5 | 5.35 |

## III. BART Evaluation

There are two BART eligible units at the Cemex facility, the dryer and the kiln. The dryer is natural gas-fired with actual emissions of NOx = 10.41 tpy; SO2= 0.89 tpy; and PM10 = 5.12 tpy; based on a recent stack test. CALPUFF modeling[1], of the dryer and kiln combined indicates a 98th percentile visibility impact (at Rocky Mountain National Park) of 0.78 delta deciview[2] ($\Delta$dv) and 98th percentile visibility impact at of only the kiln is 0.76 $\Delta$dv[3]. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 $\Delta$dv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the Division has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the Division has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any measurable visibility improvement which is a fundamental factor in the BART evaluation. Consequently, the current SO2, NOx and PM10 emission limits (see Table 1 –Dryer Allowable Emissions) established in the Cemex – Lyons Operating Permit (95OPBO082) have been determined to satisfy the requirements for BART.

### III.A. Review of Sulfur Dioxide Controls on the Kiln

Step 1: Identify All Available Technologies

Cemex originally identified four available technologies for the removal of sulfur dioxide from Portland cement kilns. A copy of Cemex's BART analysis is included with this analysis as an attachment, and provides further support and documentation for the conclusions reached herein. The Division added Dry Sorbent Injection (DSI) as another option that is available for control of

[1] Cemex Inc., Lyons Colorado - BART Five Factor Analysis; dated August 29, 2008
[2] Table 3-6 of the Cemex BART Five Factor Analysis
[3] Table 4-7 of the Cemex BART Five Factor Analysis

SO2 emissions. The Division also reviewed the RACT/BACT/LAER clearinghouse and other BART analyses develop the following list of available technologies:

1. Fuel Substitution
2. Raw Material Substitution
3. Lime Addition to Kiln Feed
4. Dry Sorbent Injection
5. Wet Lime Scrubbing

Step 2: Eliminate Technically Infeasible Options

Cemex concluded that fuel substitution and raw material substitution are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that each of the foregoing technologies is "technically feasible" for the facility, as that term is discussed in EPA's BART guidelines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

**1. Fuel Substitution:**

Cemex is authorized to burn coal, coke and tire derived fuel (TDF) at the facility, although coal is the primary fuel. The coal used in the kiln typically has a sulfur content of less than 1.5%, whereas the sulfur content of coke can be as high as 6% sulfur. Removal of SO2 is inherent to the cement manufacturing process as the hot combustion gases come in contact with the limestone generating free lime, which then reacts with the SO2 in the free gas stream resulting in removal of sulfur in the clinker product. Removal efficiencies in rotary kiln systems can range between 38% and 99% of sulfur input. Cemex estimates the SO2 removal efficiency of about 80%. Based on the low level of SO2 emissions (based on CEMS) emitted from the kiln, it is apparent that a high level of SO2 control is achieved through the inherent removal process within the kiln. Since inherent removal accounts for at least 80% reduction in kiln SO2 emissions, any further lowering of the sulfur content of the fuel results in about a 20% reduction in directly emitted SO2.

In November 2002, a preliminary performance (stack) test was conducted on the kiln that compared fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 40% reduction in SOx in the exhaust stream. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable emission control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement.

Cost of Compliance:

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about $172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above annual cost and the estimated 40% SO2 reduction, the control cost is estimated at about $4,531 per ton of SO2 reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

No impact

**2. Raw Material Substitution:**

Sulfide sulfur in the raw materials (primarily limestone), usually in the form of iron pyrite, is thermally decomposed and oxidized or "roasted" to form SO2. The pyritic sulfur reacts with oxygen according to the following reaction:

$$4FeS2 + 11O2 \rightarrow 2Fe2O3 + 8SO2$$

Using raw materials with lower pyritic sulfur content would reduce the potential for SO2 emissions from the kiln system. However, while pyrites are present in the limestone and other raw materials used at the plant, concentrations of sulfide sulfur in these materials is typically low. On average, the sulfide content of the raw materials is less than 2%. It is uncertain that lower sulfur content materials are available. Since the raw materials and fuel used at the plant already have very low sulfide sulfur, raw material substitution is not likely to produce significant sulfur reductions.

Similar to most cement plants, the Cemex facility is built near the mine source of limestone, the primary raw material for cement manufacture. To require transport of materials with lower sulfide concentrations from elsewhere would impose an economic penalty that would cause most plants to be economically infeasible. During the production of cement clinker, the limestone loses about one-third of its weight as CO2. The shipping costs for the "lost" weight in the limestone can be economically prohibitive.

The Division has determined that raw material substitution with a different source of limestone is not a practical control option as SO2 emissions vary depending on the level of pyrite contamination which is inherently difficult to predict. Consequently, raw material substitution has been eliminated from further review and consideration.

**3. Lime Addition to Kiln Feed:**

Lime Addition to Kiln Feed at the Lyons plant would consist of mixing lime (CaO) with the raw Kiln feed. The CaO would react with SO2 driven off in the kiln to form calcium sulfite (CaSO3) and calcium sulfate (CaSO4) according to the following reactions:

$$CaO + SO2 \rightarrow \quad CaSO3$$

$$CaSO3 + ½\ O2 \rightarrow \quad CaSO4$$

These reactions can occur in the calciner, throughout the rotary kiln, and in the lower stages of the flash calciner (i.e., at any location in the system at which CaO and SO2 are present simultaneously and are mixed adequately). The amount of SO2 absorbed through this mechanism at any location in the pyroprocess is dependent on the site-specific temperature and other factors such as the time of contact between the reactants. Once sulfur is absorbed as CaSO4 in the materials in the pyroprocess, it is unlikely to be released again as SO2. CaSO4 would be retained in the raw mix and ultimately be converted into clinker. Cemex anticipates that Lime Addition to Kiln Feed could achieve 25% control of the SO2 emitted from the system. Considering the length of the kiln and the corresponding amount of contact time, it appears that 25% control of SO2 is possible depending on the amount of lime that is fed into the kiln.

Cost of Compliance:

The cost of Lime Addition to Kiln Feed was determined by calculating the cost of the CaO needed to react with the SO2 in the system. In an exhaust gas stream, the molar ratio of CaO needed to react with a mole of SO2 (to achieve a near 90% reaction) is on the order of 1:1. However in the situation of Cemex – Lyons, adding the CaO directly to the feed would result in a diminished effectiveness because of the lower SO2 concentrations. Cemex has indicated that, based on data from Cemex's Wampum, PA plant, an addition of 2-3 ton/hr of CaO to a similar Kiln feed stream resulted in approximately a 25% reduction in the SO2 concentration (from 600 ppm down to 450 ppm). The concentration of SO2 in the gas stream at the Lyons plant is significantly lower (a typical 24-hr average is in the 6 ppm range) and it is unknown how much more CaO is needed to achieve the desired reduction. Since the typical emission range at Cemex-Lyons is 100 times lower than the tested levels at Cemex-Wampum, it is expected that more CaO would be needed to achieve adequate contact time with the lower concentrations of sulfur in the exhaust stream. Moreover, the effectiveness of CaO addition is further limited by the alkali byproducts associated with the use of more CaO. Consequently, Cemex has conservatively estimated that it could take about 4 tons per hour of CaO addition to achieve a 25% SO2 reduction.

Cemex – Lyons kiln is limited to 8,064 hours per year of operation based on a permit limit in the Operating Permit (95OPBO082), thus the resulting annual CaO usage is 32,256 tons (4*8064). Cemex's 2007 BART application identified the CaO cost at $60/ton, but this was for raw CaO (un-calcined) which has different properties. The appropriate material is the use of calcined CaO (lime or quick lime) which cost about $143/ton. Therefore, the annual operating cost would be 32,256 tons x $143/ton = $4,612,608. The lime (CaO) addition would yield approximately 90% conversion to clinker, or 29,030 tpy of clinker, which has a value of $1,161,216 @ $40/ton. Therefore, the actual operating cost would be approximately $4,612,608 - $1,161,216 = $3,451,392. At 25 % control effectiveness, the annual SO2 emissions would be lowered from the proposed permit limit of 95.0 tpy to 71.25 tons/year. The cost effectiveness would be approximately $153,271per ton of SO2 removed.

Energy Impacts and Non Air-Quality Impacts:

Alkali impurities in the CaO could result in additional wasting of kiln dust to meet low alkali limits. Additional fugitive PM10 emission may result from handling of the CaO.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for lime addition to kiln feed.

**4. Dry Sorbent Injection:**

Dry Sorbent Injection (DSI) utilizes finely ground sorbent which is injected in the gas stream of the kiln. The sorbent typically used is a hydrated lime, sodium bicarbonate or Trona (soda ash). Water may be injected separately from the sorbent either downstream or upstream of the dry sorbent injection point to humidify the flue gas. The relative position of the dry sorbent and water injection is optimized to maximally promote droplet scavenging or impacts between sorbent particles and water droplets, both suspended in gas stream. Fly ash, reaction products, and any unreacted sorbent are collected in the particulate control device.

Cost of Compliance:

Cemex did not provide any DSI costs specific to the Lyons kiln.

Energy Impacts and Non Air-Quality Impacts:

There are no energy or non-air quality impacts associated with dry sorbent injection.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker which results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for dry sorbent injection.

**5. Wet Lime Scrubbing:**

Wet lime scrubbing (WLS) is the term used for a traditional tailpipe wet scrubber. This process involves passing the flue gas from the main PMCD through a sprayed aqueous suspension of Ca(OH)2 or CaCO3 (limestone) that is contained in an appropriate scrubbing device. In WLS the SO2 reacts with the scrubbing reagent to form CaSO3 that is collected and retained as aqueous sludge. Typically, the sludge is dewatered and disposed in an on-site landfill. In some cases involving cement plants, the CaSO3 sludge could be oxidized to CaSO4 and used in the finish mills as a substitute for purchased gypsum for regulation of the setting time of the cement product. Typically, WLS is considered to have a scrubbing efficiency of up to 90 percent of the SO2 in the flue gas treated by the scrubber. *See* Cemex BART submittal at 4-4, *citing* "EPA Fact Sheet – Flue Gas Desulfurization (FGD) Wet, Spray Dry, and Dry Scrubbers."

Cost of Compliance:

Cemex performed an economic analysis to determine the annualized cost for WLS based on a recent vendor bid for a cement plant with a similar exhaust flow rate. The "annual tons reduced" were determined by subtracting the estimated controlled annual emissions from the Division proposed annual permit limit of 95 tpy SO2. The estimated controlled annual emissions, 9.5 tpy,

were calculated by applying 90 percent control efficiency to the 95 tpy of SO2. Utilizing this methodology and correcting a math error on the amount of sludge generated, the estimated annualized cost[4] is $2,529,018 for WLS, the projected SO2 control cost per ton is $29,579/ton. A detailed cost analysis is included in Table 4-5 of Cemex's BART submittal, which was corrected by the Division to account for the longer amortization period.

Energy and Non Air-Quality Impacts: Wet Lime Scrubbing (WLS)

Based upon its experience, the Division has determined that wet scrubbing has several negative energy and non air quality environmental impacts, including significant water usage which is a precious commodity in the arid West. Cemex estimates that an appropriately sized wet scrubber would consume approximately 16 million gallons of water per year. Most of this water would be emitted as a steam vapor with a small portion in the sludge that would be generated by the control device. A wet scrubber would also require an additional fan of considerable horsepower to move the flue gas through the scrubber.

Wet scrubbing may also lead to an increase in PM emissions at the Cemex facility, because some particles of limestone or CaSO4 will be entrained in the flue gas and subsequently be emitted from the scrubber. Wet scrubbing is also known to increase emissions of sulfuric acid mist.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln is impacted by the remaining life of the quarry, which Cemex has estimated to be approximately 8 years from the date that a BART control would be required based on the expiration of Boulder County SUP 93-14 for quarry operations. The continued viability of the cement production operation relies on finding additional limestone feedstock of very similar composition within a distance that allows for economic operation. The Division is not aware that Cemex has successfully secured additional limestone supplies that would provide additional useful life to the facility. Presently, Cemex is unwilling to consent to closure date in the operating permit therefore the Division has used 20 years as the capital recovery period.

[4] Capital Recovery based on an assumed 20 year life and 7% interest rate

Table 4 below lists the most feasible and effective options, ranked by control effectiveness.

Table 4: Kiln SO2 Control Options

| Control Technology | Estimated Control Efficiency | Annual Controlled Hourly SO2 Emissions [lbs/hr] | Annual Controlled SO2 Emissions [tpy] | Annual Controlled SO2 Emissions [lb/ton of Clinker] |
|---|---|---|---|---|
| Baseline SO2 Emissions | | 25.3 | 95.0 | 0.40 |
| Lime Addition to Kiln Feed | 25% | 19.0 | 71.3 | 0.30 |
| Fuel Substitution (coal supplemented with TDF) | 40% | 15.2 | 57.0 | 0.24 |
| Dry Sorbent Injection | 50% | 12.7 | 47.5 | 0.20 |
| Wet Lime Scrubbing (Tailpipe scrubber) | 90% | 2.5 | 9.5 | 0.04 |

Table 5 below lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 5: Summary of Cost Effectiveness of SO2 Control Technologies for the Kiln

| Control Technology | SO2 Emission Reduction [tons/yr] | Annualized Cost [$/yr] | Cost Effectiveness [$/ton] | Incremental Cost Effectiveness [$/ton] |
|---|---|---|---|---|
| Baseline SO2 Emissions | - | | | |
| Lime Addition to Kiln Feed | 23.8 | $3,640,178 | $153,271 | |
| Fuel Substitution (coal supplemented with TDF) | 38.0 | $172,179 | $4,531 | -$243,368 |
| Dry Sorbent Injection | 47.5 | Not provided | - | |
| Wet Lime Scrubbing (Tailpipe scrubber) | 85.5 | $2,529,018 | $29,579 | $49,618 |

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control scenarios. Cemex also conducted refined CALMET modeling which indicates that Rocky Mountain National Park is the only Class I Area where the Lyons plant causes or contributes to visibility impairment. Cemex's refined modeling is discussed in detail in the attached Cemex BART 5-Factor Analysis which was reviewed by the Division and found to meet all required performance requirements.

The amount of visibility improvement associated with various SO2 control scenarios using CALPUFF modeling are listed in Table 6.

Table 6: Visibility improvement for SO2 Controls – Kiln Only

| Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (from 24-hr Max) (Δdv) | Cost Effectiveness ($/Δdv) |
|---|---|---|---|
| 24-hr Maximum (≈ 104 lbs/hr) | 0.760 | - | |
| Baseline (≈ 25.3 lbs/hr)* | 0.730 | 0.030 | |
| Lime Addition to Kiln (≈ 19.0 lbs/hr)* | 0.727 | 0.033 | $110,308,420 |
| Fuel Substitution (≈ 15.2 lbs/hr)* | 0.726 | 0.034 | $5,064,088 |
| Dry Sorbent Injection (≈ 12.7 lbs/hr)* | 0.724 | 0.036 | |
| Wet Lime Scrubbing (≈ 2.5 lbs/hr) | 0.720 | 0.040 | $63,225,462 |

* - *Visibility impacts interpolated from original BART modeling*

The SO2 baseline of 95 tons/year is based on 2002 APEN report which results in a 0.03 Δdv of visibility improvement over the 24-hour maximum emission rate of 104 lb/hour (419 tons/year). The SO2 reduction from lime addition to kiln feed is estimated at 25% and the anticipated degree visibility improvement (from 24-hr Maximum) is about 0.033 Δdv at a cost of $110.3 million dollars per Δdv. The control efficiency of fuel substitution could be as high as 40% (about 38 tons/year) based on very limited testing and the anticipated degree of visibility improvement (from 24-hr Maximum) is about 0.034 Δdv at a cost of $5 million dollars per Δdv. Dry sorbent injection has a visibility improvement of 0.036 Δdv, based on an estimated 47.5 tpy reduction in SO2 emissions. Wet lime scrubbing reduces SO2 emissions by about 85.5 tpy with 0.04 Δdv visibility improvement at a cost of $63 million dollars per Δdv. The visibility projections for the below listed emission levels are based on scaling the existing BART modeling.

Step 6: Select BART Control

The Division reviewed the Cemex data on raw material substitution. Since the raw materials (mostly limestone) consumed at the plant typically have low sulfide sulfur content, material substitution would not result in a significant reduction in SO2 in the Kiln. The Division agrees that raw material substitution is not an appropriate or realistic SO2 control technology for the Kiln.

The Division has eliminated the Lime Addition to Kiln Feed SO2 control option from consideration based on excessive cost ($153,271 per ton) and minimal visibility improvement (0.033 Δdv). Despite not having cost information on Dry Sorbent Injection, the Division has determined that the minimal visibility improvement of 0.036 Δdv does not justify further consideration of this control technology.

The Division has eliminated the Wet Lime Scrubbing SO2 control option from consideration based on excessive cost ($29,579 per ton) and minimal visibility improvement (0.04 Δdv improvement). Moreover, wet scrubbing has a number of adverse energy and environmental impacts as described above.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that process control (inherent removal in the kiln) from the 2002 baseline period represents Best Available Retrofit Technology for control of SO2 emissions in the kiln. Table 7 specifies the Division SO2 BART determination of 25.3 pounds per hour and 95.0 tons

per year that are 12-month rolling averages. The Division considered establishing an SO2 emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the SO2 BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 7: SO2 Emission Limits on the Kiln

| Subject Unit | SO2 Control Technology | SO2 Emission Limits |
|---|---|---|
| Kiln System | Inherent Removal | 25.3 lbs/hr (12-month rolling average) |
| | | 95.0 tons/yr (12-month rolling average) |

The federal BART rule requires that emission limits must be enforceable and specify a reasonable averaging time consistent with established reference methods. The Division finds that in consideration of the potential for variability in SO2 emissions associated with pyrites in the limestone and other raw materials used at the plant, an annual averaging period provides long-term compliance with the low levels of SO2 emitted from the kiln while allowing for short-term variability in SO2 emissions. Shorter term averaging periods are not practical as the sources of the sulfur impurities are not readily detectable in the quarry materials. The type of cement produced also potentially impacts the variability of SO2 emissions in the kiln feed mix which necessitates longer averaging periods.

In consideration of establishing the SO2 emission limit, the Division reviewed not only the 5 factor analysis, but also looked at emission limits from the RACT/BACT/LAER clearinghouse to determine SO2 emission limits for other cement kilns across the nation. The Division was unable to find an operationally similar kiln to the Cemex - Lyons kiln, but the SO2 emission limits for newer higher efficiency kilns do establish a reasonable range to consider. Table 8 identifies SO2 limits ranging from 0.2 to 12.0 lb per ton of clinker. In comparing the Division proposed SO2 BART limit (approximately equal to 0.40 lb per ton of clinker) to the values approved for new Portland cement kilns in the RACT/BACT/LAER clearinghouse, it is well below the higher limits established in Missouri, and is slightly higher than those established in Florida.

Table 8: RACT/BACT/LAER data for Cement Kilns

| RBLC ID | SO2 Control | SO2 Limit | Units | Year |
|---|---|---|---|---|
| FL 0297 | Process | 0.2 | lb/ton clinker | 2007 |
| MO-0072 | Process | 1.93 | lb/ton clinker | 2006 |
| FL-0271 | Process | 0.2 | lb/ton clinker | 2006 |
| FL-0268 | Process | 0.23 | lb/ton clinker | 2004 |
| FL-0267 | Process | 0.28 | lb/ton clinker | 2004 |
| SD-003 | Process | 632 | ton/hr | 2003 |
| MO-0059 | Wet Scrubber | 12 | lb/ton clinker | 2002 |
| IA-0052 | Process | 4850 | ton/year | 2002 |
| TX-0355 | Process | 20 | lb/hr | 2001 |
| FL-0139 | Process | 0.27 | lb/ton clinker | 2000 |

The Division also evaluated a recent local BACT determination (2007) on Grupo Cementos de Chihuahua (GCC) Rio Grande Pueblo Portland cement plant that establishes a SO2 emission limit of 1.99 lb/ton of clinker. In considering the RBL clearinghouse ranges and a recent Colorado BACT determination, the Division finds that the proposed SO2 BART limits (approximately equal to 0.40 lb/ton of clinker) to be a reasonable limit for such a relatively small SO2 emission source.

Accordingly, based upon its consideration and weighing of the five factors, the Division has determined that the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual SO2 emission limits of 25.3 lbs/hour and 95.0 tpy (approximately equal to 0.40 lb per ton of clinker) as SO2 BART for the kiln at this facility. No additional controls are warranted because about 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

### III.B. Review of Nitrogen Oxide Controls on the Kiln

As explained above, in Section III, no evaluation of the dryer is warranted because of extremely low emissions. Based on actual 2008 data, the NOx emissions from the kiln are 1295.5 tpy and the raw material dryer are 10.41 tpy. Since the average emissions from the dryer (about 2.8 pounds per hour) are very small compared to the kiln (about 343.9 pounds per hour); the following BART evaluation focuses only on the kiln.

Step 1: Identify All Available Technologies

The primary pollutant of concern for regional haze from the Lyons plant is the NOx generated from the kiln system. Cemex's current allowable NOx emission rate is 2,649 tpy NOx, which equates to an average allowable emission rate of 667 pounds NOx per hour based on the permit limit of 8064 hours of operation per year. Using 2002 as the baseline, the annual average NOx emission rate is 464.3 lbs/hr (1,747.1 tpy) or about 4.73 lbs/ton of dry kiln feed.

Variations in kiln NOx emissions occur with the composition of the raw materials used to produce different types of cement, which depends on market demand. Also, changes in the raw materials (natural rock composition) and seasonal temperature variations occur, as indicated in the following excerpt from a study[5], *"The results of these changes range from zero emissions of NOx during a complete outage of the system to significantly higher than normal NOx emissions when the fuel input is increased to restore the process equilibrium and a normal production rate. More subtle changes in the process, e.g. variations in ambient temperature (short-term and seasonal), variations in the feed rates or fuel or raw materials, demand operator responses that also serve to vary NOx emissions. For a variety of factors, the operation of some pre-calciner kiln systems is more stable than others. Almost invariability, however, pre-calciner kiln systems exhibit more stable operation than the three other types of kiln systems, and experience the least variability in NOx emissions."* The Cemex - Lyons kiln is a modified long dry kiln, thus some consideration of a longer averaging period is appropriate to account for variation in NOx emissions depending on cement product produced and variations in raw materials.

[5] See "Variability of NOx Emissions from Precalciner Cement Kiln Systems", Walter L. Greer, Curtis D. Lesslie

Cemex identified six available technologies for the removal of NOx from Portland cement kilns. The Division reviewed the RACT/BACT/LAER Clearinghouse and other BART analyses and agrees with CEMEX's identification of available technologies. The available technologies are the following:

1. Water Injection
2. CKD Insufflation
3. Firing Tire-Derived Fuel
4. Indirect Firing with Low NOx Burners (LNB)
5. Selective Non Catalytic Reduction (SNCR)
6. LNB with SNCR
7. Selective Catalytic Reduction (SCR)

Step 2: Eliminate Technically Infeasible Options

Cemex has concluded that water injection and kiln dust insufflation are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that these technologies are "technically feasible" for the facility, as that term is discussed in EPA's BART guidelines. As further discussed below, however, the Division has also determined that water injection and kiln dust insufflation are not appropriate NOx controls for purposes of BART at the facility.

**7. Selective Catalytic Reduction (SCR):**

Selective catalytic reduction (SCR) refers to the reduction of NOx in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term "selective" refers to the unique ability of ammonia to react selectively with NOx. The EPA released a NOx control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns," EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

*SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce $NO_x$ emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce $NO_x$ emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith form) and promotes the $NO_x$ reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C] ), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:*

$$4\ NH3 + 4\ NO + O2 \rightarrow 4\ N2 + 6\ H2O$$
*and*
$$4\ NH3 + 2\ NO2 + O2 \rightarrow 3\ N2 + 6\ H2O$$

*The first equation is the predominant reaction because 90-95% of $NO_x$ in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a $NH_3$: $NO_x$ molar ratio of 1.05–1.1:1 to achieve a $NO_x$ conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The $NO_x$ removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to $NO_x$, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired $NO_x$ reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:*

*After the PM control device – a "low-dust" system*
*After the last cyclone without ducting – a "high-dust" system.*

*The advantages of a "low-dust" system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 $mg/m_3$ (~ 0.8 lb/t) of $NO_x$ is typically achieved from an inlet of 1,050 $mg/Nm_3$ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 $mg/m_3$. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.*

*The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.*

The design of a SCR system is expected to be site specific. According to Schreiber[6], the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 1, from Granger[7] shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NOx reduction

[6] See Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)
[7] See Granger, P. Elsevier, "Past and Present in DeNOx Catalysis: From Molecular Modeling to Chemical Engineering", (2007)

efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350°C to 450°C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NOx reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

Figure 1: Catalyst Performance for NOx Control and Ammonia slip at Various Temperatures

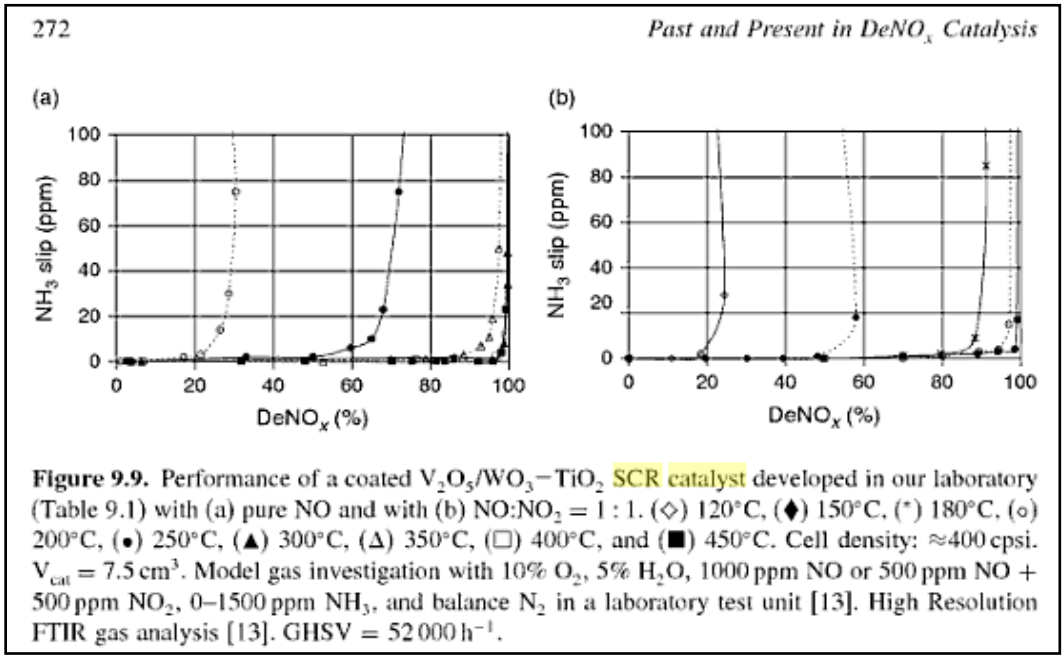



**Figure 9.9.** Performance of a coated $V_2O_5/WO_3-TiO_2$ SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) NO:$NO_2$ = 1 : 1. (◇) 120°C, (♦) 150°C, (*) 180°C, (○) 200°C, (●) 250°C, (▲) 300°C, (Δ) 350°C, (□) 400°C, and (■) 450°C. Cell density: ≈400 cpsi. $V_{cat}$ = 7.5 cm$^3$. Model gas investigation with 10% $O_2$, 5% $H_2O$, 1000 ppm NO or 500 ppm NO + 500 ppm $NO_2$, 0–1500 ppm $NH_3$, and balance $N_2$ in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 h$^{-1}$.

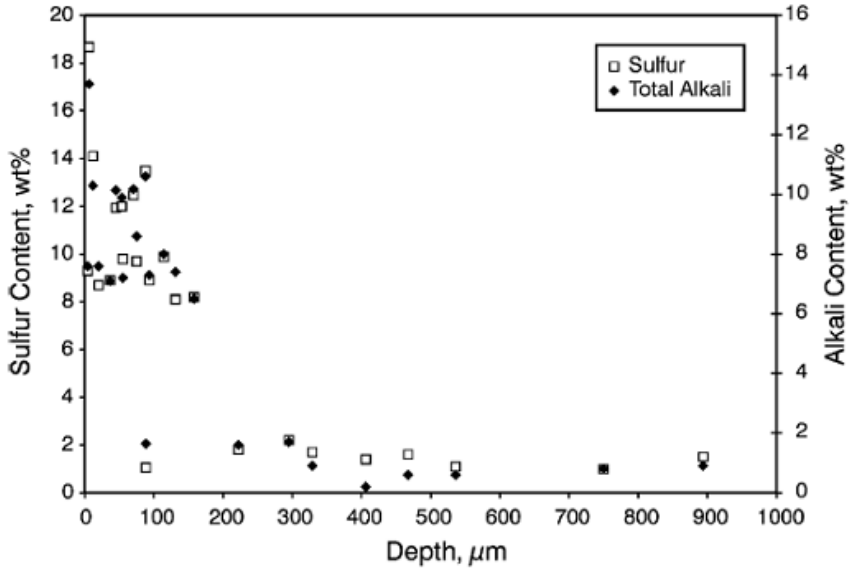
Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. Each challenge presents additional confounding issues related to the application at the Cemex – Lyons facility due to the unique design of the modified long dry kiln. A good catalyst must ensure high activity and selectivity for NOx reduction and low activity in the oxidation of SO2 to SO4. Because of the high selectivity, the catalyst will have a specific temperature window at which the NOx reduction is optimal (Granger 2007). Specific to the Cemex – Lyons kiln, the exit temperature, after the baghouse, will require reheating of the exhaust gases to reach the optimal temperature for effective NOx control. If post NOx control cooling is required, additional water usage would be necessary along with the challenges of the resultant high moisture (20-25%) exhaust gas stream.

There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NOx reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson[8], alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.,* 2008, and Strege *et al.,* 2008). Figure 2 shows evidence of catalyst poisoning by both sulfur and alkalies[9].

[8] See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)
[9] See Strege, J. et al., "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NOx control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NOx reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst. The exit gas of the Cemex – Lyons kiln presents additional specific issues including moisture in the exhaust stream and alkali dust. The combination of both could result in rapid loss of catalyst activity depending on the type of catalyst materials used.

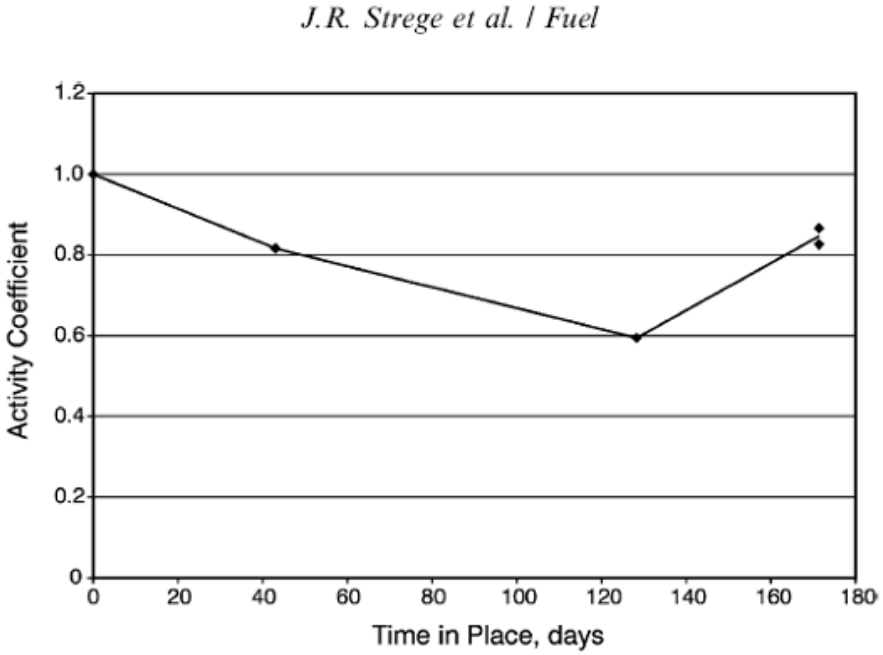
Figure 2: Sulfur and Alkali Penetration into the pores of the catalyst




Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

The above figure indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NOx reduction (see Strege *et al.*, 2008).

Figure 3: Bench Scale Test Results of Catalyst Deactivation over a Period of Time




Bench-scale test results of catalyst deactivation with time.

The above figure provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NOx conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro[10], a good flow distribution is needed to ensure minimal ammonia slip. The Cemex – Lyons kiln has neither the temperature nor the flow characteristics necessary for optimal catalyst performance. Another concern for the Cemex – Lyons kiln, is the potential for ammonia slip to create visibility impairment that is readily transported into nearby Rocky Mountain National Park.

Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time.

Of the four major vendors contacted, two, Lurgi PSI Inc. (Lurgi) and Babcock & Wilcox, did not provide any proposal, with Lurgi stating that their technology was not yet ready for commercial release. A third with relevant experience from the Solnhofen demonstration plant, KWH, indicated that technical uncertainties prevented them from designing an SCR system. Only Alstom provided a proposal that suggested SCR could be supplied to a cement kiln system.

[10] See Barbaro, P.; Bianxhini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

However, careful review of the Alstom proposal indicated that the Alstom proposal did not identify a commercial SCR system that would be viable for a cement kiln system application.

The Division finds that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe that differ significantly from the Cemex – Lyons kiln design does not constitute "available" control technology for purposes of BART. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *"The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst*." Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse as would be required for the Cemex - Lyons kiln, which is a modified long-dry kiln design. The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be "available" for purposes of retrofitting such control technology on an existing source. BART should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, the Division has eliminated SCR as an available control technology for purposes of BART.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

**1. Water Injection:**

The injection of water or steam into the main flame of a kiln can act as a heat sink to reduce the flame temperature. Since NOx formation is a function of the flame temperature and residence time at that temperature, water injection reduces the generation of thermal NOx. Cemex - Lyons has stated that its own experience indicates that water injection can reduce the thermal NOx by approximately 7%. The Division anticipates some reduction in thermal NOx formation when water is injected into the area where the flame temperature is the highest. Aside from actual testing in the kiln, a 7% reduction seems reasonable.

Cost of Compliance:

Based on information from Cemex – Lyons, the Division estimates the annualized costs of water injection at about $43,598 with minimal annual operating costs. Assuming a 7% NOx reduction, the control cost is about $356 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

The only non-air quality impacts associated with water injection is the use of a precious resource in limited supply in the arid west.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for water injection.

**2. Cement Kiln Dust Insufflation:**

Cement Kiln Dust (CKD) is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. CKD is most often treated as a waste even though there are some beneficial uses. However, as a means of recycling usable CKD to the cement pyroprocess, CKD sometimes is injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame has the effect of cooling the flame and/or the burning zone thereby reducing the formation of thermal NOx. The insufflation process is somewhat counterintuitive because a basic requirement of a cement kiln is a very hot flame to heat the clinkering raw materials to about 2700°F in as short a time as possible. Because of the thermal inefficiency associated with the practice, CKD insufflation is not an attractive control option for NOx. While the Division does not agree that the thermal inefficiency makes kiln dust insufflation technically infeasible, the Division has determined that that inefficiency, coupled with the much greater reduction achieved through SNCR (discussed below), render insufflation inappropriate for the Cemex plant. Cemex provided additional information that indicates that CKD insufflation is not typically done because of operational issues including ring formation in the kiln. Consequently, the Division is not evaluating this control option further because of operational issues and the greater reduction achieved through SNCR.

**3. Firing Tire-Derived Fuel:**

Secondary combustion is defined as follows: a portion of the fuel is fired in a location other than the burning zone. This reduces thermal NOx generation because the temperature in the secondary combustion zone is less than 2100 °F. Firing of solid fuels, such as used tires, is an example of secondary combustion. The Cemex – Lyons kiln has conducted testing of tire derived fuel (TDF) which can be introduced at the kiln feed shelf, creating a secondary combustion zone in the riser between the kiln and the combustion chamber.

In November 2002, a preliminary performance (stack) test was conducted to compare fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 24.4 % reduction in NOx in the exhaust stream. Cemex estimates that firing TDF can reduce NOx by 10% on a long term basis if utilized. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable NOx reduction control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement. Potentially, TDF could be used in combination with other control technologies, such as SNCR to meet additional BART NOx reduction objectives.

Cost of Compliance:

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about $172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above

annual cost and the estimated 10% NOx reduction, the control cost is estimated at about $986 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact

**4. Indirect Firing with Low-NOx Burners:**

Low NOx burners (LNBs) reduce the amount of NOx formed at the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). As applied to the rotary cement Kiln, the low-NOx burner creates primary and secondary combustion zones at the end of the main burner pipe to reduce the amount of NOx initially formed at the flame. In the high-temperature primary zone, combustion is initiated in a fuel-rich environment in the presence of a less than stoichiometric oxygen concentration. The oxygen-deficient condition at the primary combustion site minimizes thermal and fuel NOx formation and produces free radicals that chemically reduce some of the NOx that is being generated in the flame.

In the secondary zone, combustion is completed in an oxygen-rich environment. The temperature in the secondary combustion zone is much lower than in the first; therefore, lower NOx formation is achieved as combustion is completed. CO that has been generated in the primary combustion zone as an artifact of the sub-stoichiometric combustion is fully oxidized in the secondary combustion zone.

The EPA has indicated that a 14% reduction in NOx emissions may be anticipated in switching from a direct-fired standard burner to an indirect-fired LNB. This is based on a study conducted on an indirect-fired LNB at the Dragon Product Company cement kiln at the plant located in Thomaston, Maine. However, the EPA has also determined that the emission reduction contribution of the LNB itself and of the firing system conversion direct to indirect cannot be isolated from the limited data available. The terms direct and indirect firing have unique meaning in the context of Kiln firing (unlike the more general meanings where direct firing implies that the products of combustion contact the process materials whereas indirect firing involves a heat transfer medium). In Kiln firing, direct and indirect firing describes the manner in which pulverized fuel is conveyed from the fuel grinding mill to the burner. Cemex has estimated that a LNB would lower NOx by 20% at the Lyons plant.

Cost of Compliance:

Cemex also provided information from a NESCAUM report (Dec 2000) that indicates 20-30% NOx reduction can be achieved through the use of indirect firing with LNBs. Cost data was included from a study of California Portland Cement (Colton, CA) that evaluated TDF along with indirect firing w/LNBs that indicates $7 million capital cost and $350,000 annual O&M costs. This study includes TDF firing and does not separate out the actual cost associated with

the indirect firing with LNBs. The Division has estimated the annualized cost at about $710,750 with a result control cost of about $2,034 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact

**5. Selective Non-Catalytic Reduction (SNCR):**

In the relatively narrow temperature window of 1600 to 1995°F, ammonia (NH3) reacts with NOx without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions.

$$4NO + 4NH3 + O2 \rightarrow 4N2 + 6H2O$$

$$2NO2 + 4NH3 + O2 \rightarrow 3N2 + 6H2O$$

As applied to NOx control from cement kilns and other combustion sources, this technology is called Selective Non-Catalytic Reduction (SNCR). Above this temperature range, the NH3 is oxidized to NOx, thereby increasing NOx emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH3 could be delivered to the kiln system through the use of anhydrous NH3, or an aqueous solution of NH3 (ammonium hydroxide) or urea [(NH2)2CO]. A concern about application of SNCR technology is the breakthrough of unreacted NH3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO2, sulfur trioxide (SO3), hydrogen chloride (HCl) and/or chlorine (Cl2) to form a detached plume of PM10 –PM2.5.

SNCR is being evaluated at 45 to 50% control efficiency depending on the averaging period. The Cemex kiln/flash calciner configuration is best described as a modified long dry kiln. The Division has conducted extensive research and has not found any documentation on similar kiln types. EPA's Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns (November 2007) addresses only new cement kilns. These new kilns are multi-stage (4 or 5 stage) preheater/precalciner kilns and are not comparable to Cemex – Lyons unusual modified long dry kiln. The Division has also considered the Cemex Brooksville plant in Florida, but it is a multi stage preheater design and is not comparable to the Lyons facility. The Division's evaluation reveals that the Solnhofen facility achieved only 50% reduction with SCR. Significantly, the Division is concerned that requiring a higher reduction through SNCR (beyond 45% on a 30 day rolling average) could cause excessive ammonia slip that would exacerbate the nitrogen deposition concerns at Rocky Mountain National Park. Considering the close proximity of Cemex to RMNP, any unreacted ammonia (slip) is available to react with oxides of nitrogen or sulfur to form particulates (nitrate or sulfate) a potentially significant contributor to visibility impairment.

It is important to note, that all kilns are not created equal. Modern 5-stage preheater/calciner kilns are not an appropriate comparison to the unusual and modified configuration of the Cemex

– Lyons 40-year old kiln. Consequently, it is difficult to assert what amount of NOx reduction can be achieved with SNCR controls on this older modified long dry kiln. It is important to realize that a higher SNCR control efficiency in a long type kiln necessitates the injection of more ammonia (higher molar ratio) to increase the opportunity for reacting with oxides of nitrogen. This is particularly important to understand with older kilns where operating parameters are often less than the engineering ideal. Often residence time and temperature limit the effectiveness of the reaction. Any excess ammonia (slip) that fails to react, largely because the temperature is too low, is exhausted out the stack to eventually form particulates which counteracts the original basis for the emissions control –visibility. Thus, if EPA desires higher control efficiency, the penalty is more visibility impairment downwind of the source. Therefore, the engineering evaluation must consider the balance between high control efficiency and ammonia slip.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about $1,636,636 per year. Assuming a 48.43% NOx reduction, the control cost is about $1,934 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

**6. Selective Non-Catalytic Reduction with Low NOx Burners (LNB):**

Cemex conducted a BART analysis for the kiln located in Lyons, Colorado and concluded that SNCR could reduce nitrogen oxides (NOx) emissions on a long-term basis by about 50 percent. Various entities have suggested that Cemex provide an analysis combining low NOx burners and SNCR with the goal of achieving a higher NOx reduction, perhaps as high as 60 percent. Accordingly, this analysis has been revised to evaluate the combination of low NOx burners and SNCR.

In the cement manufacturing industry, it is well known that thermal NOx represents the majority of the NOx formation in cement kiln systems. Thermal NOx is a side effect of the high temperatures necessary in the cement kiln to produce a quality clinker product. One effort to combat the thermal NOx formation in the cement industry has been the installation and use of LNB. LNB have been used to a limited degree in the cement industry for over 30 years. The concept of LNB is to minimize primary air as a source of nitrogen, reduce flame turbulence, delay air and fuel mixing, and establish a fuel rich zone for initial combustion. The resulting longer, less intense flame from the staging of combustion in this manner reduces flame temperatures and is therefore thought to reduce thermal NOx formation.

In practice, LNB create two distinct combustion zones: the primary and the secondary combustion zones. In the primary, or initial, combustion zone flame turbulence and air and fuel mixing are suppressed by decreasing the amount of primary air supplied to the burning zone. It

is well understood that the higher the primary air, the higher the NOx from the kiln system.[11] Typical primary air for LNB ranges from 5 to 7 percent.[12] The result is a fuel-rich, oxygen-lean, high temperature combustion zone created by reducing the amount of primary air and delaying the combustion of all of the fuel. The peak flame temperatures in the primary combustion zone must be maintained high to initiate the clinkering reactions. However, thermal NOx formation is thought to be suppressed due to the oxygen-lean environment in the primary combustion zone which generates excess CO and other radicals known to react with NOx.

The primary combustion zone is followed by an oxygen-rich secondary combustion zone where fuel combustion is completed. Lower temperature secondary combustion air is mixed into the secondary combustion zone, thereby lowering the peak combustion temperatures. Although excess oxygen is available, $NO_x$ formation is suppressed in the secondary combustion zone because the temperatures are insufficient for significant thermal NOx formation.

The Lyons Plant is currently equipped with a two channel, straight pipe burner with one channel for coal and a second channel for air used to adjust the momentum of the flame. The burner configuration is closer to a mono-channel than to a multi-channel burner definition. The measured primary air at the Lyons Plant ranges from 40 to 65 percent accordingly to the amount of momentum air used, with most of the primary air coming from the coal mill's minimum air evacuation requirements. The application of LNB at the Lyons Plant would primarily consist of replacing the existing main kiln burner.

The level of NOx reduction reported in the literature for LNB applications on cement kiln systems vary considerably. Factors affecting the variability include, but are not limited to the specific type of LNB, pre-installation NOx emission levels, kiln type, and fuels used. According to EPA's "Alternative Control Techniques Document Update – NOx Emissions from Cement Manufacturing," EPA-453/R-94-004, March 2004, the NOx reduction achievable with LNB ranges from 20 to 30% for typical kiln systems. The level of control achieved is generally greater for newer kiln systems. Many older kiln systems may achieve lower NOx reductions due to the specific operating characteristics of the kiln systems. There are also a few non-typical kiln systems in the US, with one being the Lyons Plant. Considering the unique design and age of the Lyons Plant cement kiln system, it is uncertain whether meaningful NOx reductions would be expected from the installation of LNB in combination with SNCR.

Cemex has proposed the installation and use of SNCR to achieve about a 50% NOx reduction (long term) at the Lyons Plant. This level of NOx reduction has been demonstrated on several cement kiln systems in the US, is recognized in the recently EPA proposed New Source Performance Standards as the demonstrable control efficiency for SNCR, and represents a high level of control with little risk of the known side effects to ammonia injection. The main risk for SNCR is the formation of a detached plume attributable to excessive ammonia slip due to injecting at too high of a normalized stoichiometric ratio (NSR) (i.e., pushing the SNCR technology too far to achieve higher levels of NOx reduction leads to the formation of a detached ammonia plume, called ammonia slip). Ammonia slip from SNCR is non-existent to minimal when the reagent is injected at or below an NSR of about 0.7. Operating SNCR above this NSR significantly increases the ammonia slip to the point where conditions are favorable for the

[11] Battye, R., Walsh, S., and Greco, J. 2000. NOx control technologies for the cement industry. Final report. Pages 30-31. EPA contract No. 68-D98-026.
[12] Battye, R., Walsh, S., and Greco, J. 2000. NOx control technologies for the cement industry. Final report. Page 59. EPA contract No. 68-D98-026.

formation of a detached plume containing ammonium chloride and ammonium sulfide compounds. These compounds, as well as any unreacted ammonia, would result in visibility degradation which is counter to the intent of BART.

Therefore, the Division concludes that given the reasonable uncertainty in the benefits of LNB, the existing proposal to utilize the existing burner along with SNCR remains the best control option for the Lyons Plant kiln.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about $1,686,395 per year. Cemex provided an estimated 55% NOx reduction resulting in an estimated control cost of about $1,755 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

Table 10 below contains a ranking by control effectiveness of the remaining control technologies.

Table 10: Kiln NOx Control Options

| Control Technology | Estimated Control Efficiency | Annual Controlled Hourly NOx Emissions [lbs/hr] | Annual Controlled NOx Emissions [tpy] | Annual Controlled NOx Emissions [lb/ton of Clinker] |
|---|---|---|---|---|
| Baseline NOx Emissions | - | 464.3 | 1,747.1 | 7.39 |
| Water Injection | 7% | 431.8 | 1,624.8 | 6.87 |
| Firing TDF | 10% | 417.8 | 1,572.3 | 6.65 |
| Indirect Firing with LNB | 20% | 371.4 | 1,397.6 | 5.91 |
| SNCR | 45% | 255.3 | 960.9 | 4.06 |
| SNCR | 48.43% | 239.4 | 901.0 | 3.81 |
| SNCR w/LNB | 55% | 208.9 | 786.2 | 3.33 |
| SCR | Not technically feasible | | | |

Table 11 below lists the NOx emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 11: Summary of Cost Effectiveness of NOx Control Technologies for the Kiln

| Control Technology | NOx Emission Reduction [tons/yr] | Annualized Cost [$/yr] | Cost Effectiveness [$/ton] | Incremental Cost Effectiveness [$/ton] |
|---|---|---|---|---|
| Baseline NOx Emissions | - | | | |
| Water Injection | 122.3 | $43,598 | $356 | |
| Firing TDF | 174.7 | $172,179 | $986 | $2,453 |
| Indirect Firing with LNB | 349.4 | $710,750 | $2,034 | $3,083 |
| SNCR (45% control) | 786.2 | $1,636,636 | $2,082 | $2,120 |
| SNCR (48.43% control) | 846.1 | $1,636,636 | $1,934 | $1,864 |
| SNCR w/LNB (55% control w/uncertainty) | 960.9 | $1,686,395 | $1,755 | $434 |

Based on the above discussion, the combination of SNCR with LNB has an uncertain level of control due to the unique nature of the Lyons kiln. The Division has determined that SNCR is the best available NOx control option for the Cemex – Lyons modified long dry kiln. Because Cemex has proposed SNCR as the preferred control option, it is not necessary or appropriate to further evaluate the lesser control options, including relative costs.

SNCR requires injection of the reagents in the kiln at a temperature between 870 to 1,090°C (1,600 to 2,000°F). In principle, any of a number of nitrogen compounds may be used as SNCR reagents (e.g., cyanuric acid, pyridine, and ammonium acetate). However, for reasons of cost, safety, simplicity, and by-product formation, ammonia and urea have been used in most of the SNCR applications. The selection of reagents is process and temperature specific. At higher temperatures, urea decomposes to produce ammonia, which is responsible for $NO_x$ reduction. In cement kiln applications, ammonia typically has performed best as the reducing reagent. Because no catalyst is used to increase the reaction rate, the temperature window is critical for conducting this reaction. At higher temperatures, the rate of a competing reaction for the direct oxidation of ammonia, which actually forms additional $NO_x$, becomes significant. At lower temperatures, the rates of $NO_x$ reduction reactions become too slow resulting in too much unreacted ammonia being released to the atmosphere (i.e., ammonia slip). The effective temperature window range can be lowered to about 700°C (1,300°F) by the addition of hydrogen along with the reducing agent.

The $NO_x$ reduction efficiency of SNCR depends upon the temperature, oxygen, carbon monoxide, and residence time, as well as the ammonia and $NO_x$ concentrations in the flue gas. Injection of ammonia at a $NH_3$:3 $NO_x$ proportion of 1 to 1.5 will reduce $NO_x$ emissions between 60 to 80 percent. Using a molar ratio of 0.5 will give $NO_x$ reductions of approximately 40 percent. Work done by the German equipment supplier Polysius has shown that the optimum temperature for reduction of $NO_x$ by ammonia is about 950ºC (1,740ºF), while for urea, the temperature increases to about 1,000ºC (1,830ºF).

Operating experience has identified several concerns with both ammonia and urea-based SNCR processes. The most frequently reported is the buildup of ammonium bisulfite or bisulfate scale, which is significant for sulfur-containing fuels. SNCR processes also appear to convert some $NO_x$ to $N_2O$. The rate of $N_2O$ formation is a weak function of both the reactant and the NO

concentration. However, $N_2O$ formation seems to be inherently more prevalent in systems using urea than those using ammonia.

The $NO_x$ destruction efficiency also depends upon the flue gas residence time in the appropriate temperature window. Unlike an SCR system where the reaction temperature is controlled in a dedicated reactor, an SNCR system relies on the existing gas temperature profile to provide an adequate residence time for a desired $NO_x$ destruction. Maximum achievable $NO_x$ reduction in a cement kiln may thus depend upon the gas temperature profile.

Based on the foregoing discussion and the potential for ammonia slip, the Division concludes that an assumed 45% NOx reduction (30-day rolling average) and 48.43% NOx reduction (annual average) from 2002 baseline is reasonable.

Step 5: Evaluate Visibility Results

An impact analysis was conducted to assess potential visibility improvements associated with SNCR. CALPUFF modeling was used as part of this analysis. The visibility improvement associated with various scenarios was calculated as the difference between the existing visibility impairment and the visibility impairment for the controlled emission rates as measured by the 98$^{th}$ percentile modeled visibility impact. Based upon the modeling, the addition of SNCR is projected to result in a 0.41 dv improvement.

Table 12: Visibility improvement for NOx Controls – Kiln Only

| Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (from 24-hr Max) (Δdv) | Cost Effectiveness ($/Δdv) |
|---|---|---|---|
| 24-hr Maximum (≈ 656.9 lbs/hr)) | 0.760 | | |
| Revised Baseline ( ≈ 464.3 lbs/hr)* | 0.572 | 0.188 | |
| Original Baseline (≈ 446.8 lbs/hr)* | 0.555 | 0.205 | |
| Water Injection (≈ 431.8 lbs/hr)* | 0.540 | 0.220 | $198,174 |
| Firing TDF (≈417.9 lbs/hr)* | 0.526 | 0.234 | $735,807 |
| Indirect Firing with LNB (≈ 371.4 lbs/hr)* | 0.481 | 0.279 | $2,547,493 |
| Original BART Limit – SNCR (≈ 268.0 lbs/hr) | 0.380 | 0.380 | |
| Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)** | 0.368 | 0.392 | $4,175,091 |
| Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)** | 0.352 | 0.408 | $4,011,363 |
| SNCR w/LNB (≈208.9 lbs/hr) ** | 0.322 | 0.438 | $3,850,217 |

* - *Visibility impacts interpolated from original BART CALPUFF modeling*
** - *Visibility impacts extrapolated from original BART CALPUFF modeling*

Step 6: Select BART Control

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500$^{o}$F) is significantly higher at the exit than a more typical preheater precalciner kiln (650$^{o}$F). This is a significant distinction that limits the location and residence time available for

an effective NOx control system. As discussed above, the combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that SNCR represents Best Available Retrofit Technology for control of NOx emissions from the kiln. Table 13 specifies the Division NOx BART determination of 255.3 pounds per hour (30-day rolling average) and 901.0 tons per year (12-month rolling average). The Division considered establishing a NOx emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the NOx BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 13: NOx Emission Limits on the Kiln

| Subject Unit | NOx Control Technology | NOx Emission Limits |
|---|---|---|
| Kiln System | Selective Non-Catalytic Reduction (SNCR) | 255.3 lbs/hour (30-day rolling average) |
| | | 901.0 tons/year (12-month rolling average) |

The Division has reviewed the analysis provided by Cemex and agrees that SNCR is the appropriate NOx control technology. In reviewing the proposed emission rate of 255.3 lbs/hour (approximately equal to 4.06 lb/ton of clinker), the Division also looked at the RACT/BACT/LAER clearing house (see Table 14 below). The NOx rate of 4.06 lb/ton clinker is consistent with determinations made in Iowa and Missouri, but is about double the proposed limits for the newer Florida kilns. The Cemex – Lyons facility is an older modified long dry kiln and does not have the precalciner systems developed for newer facilities specifically to reduce the temperatures for clinker formation. The use of lower temperatures also reduces the formation of thermal NOx.

Table 14: RACT/BACT/LAER data for NOx emissions from Portland Cement Kilns

| RBLC ID | NOx Control | NOx Limit | Units | Year |
|---|---|---|---|---|
| FL 0297 | SNCR | 1.5 | lb/ton clinker | 2007 |
| FL-0271 | SNCR | 1.95 | lb/ton clinker | 2006 |
| FL-0268 | SNCR | 1.95 | lb/ton clinker | 2004 |
| FL-0267 | SNCR | 1.95 | lb/ton clinker | 2004 |
| SD-003 | Preheater/calciner | 2267 | tons/yr | 2003 |
| MO-0059 | SNCR | 8 | lb/ton clinker | 2002 |
| IA-0052 | Process | 4 | lb/ton clinker | 2002 |
| TX-0355 | Process | 660 | lb/hr | 2001 |
| FL-0139 | Process | 2.9 | lb/ton clinker | 2000 |

The Division also reviewed the *U.S. v. Lafarge* Consent Decree, dated January 21, 2010. In that recent action, the NOx reduction requirements established under the kiln retrofit options require

SNCR with a 12-month rolling emission limit of 4.89 lbs NOx/ton of clinker. The BART Regulations do not require the demolition and reconstruction of any facility that is subject-to-BART. The proposed Cemex BART limit compares favorably to similar units addressed by the *Lafarge* Consent Decree and the RACT/BACT/LAER clearinghouse. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Because the Cemex kiln is a modified long dry kiln and is not directly comparable to the reported limits listed in the RACT/BACT/LAER clearinghouse, the Division finds that requiring an emission rate that falls into the range for modern sources that are more thermodynamically efficient (produce less NOx) helps to further validate the stringency of the NOx emissions rate selection.

The Division is aware that Cemex may be able to do better than a 45% reduction, and will require that 48.43% reduction on an annual basis (901.0 tons per year, 12-month rolling average). This limit results in reductions that are 68% lower than the current allowable NOx limit (2,649 tpy) contained in the operating permit.

The Division also notes that the flash vessel at Cemex - Lyons is unique and may affect how well SNCR will perform at the plant. Because of this uncertainty the Division will not specify the ammonia injection or slip rate but will allow Cemex - Lyons to meet the NOx limits through SNCR technology and process controls. Improving process controls may allow Cemex - Lyons to limit formation of NOx in the kiln and thus meet the NOx limits while reducing ammonia use. By requiring a 48.43% reduction on an annual basis, the Cemex BART determination almost matches the reductions achieved for both SCR and SNCR at the Solnhofen facility.

Accordingly, based upon its analysis and consideration of the five factors, the Division has determined that the higher NOx emission rate is reasonable for the older cement kiln process, and that SNCR control at 255.3 lb/hr NOx on a 30-day rolling average (which is about 4.06 lbs of NOx per ton of clinker) is NOx BART for the Cemex – Lyons facility. This BART determination will remove 45% of the NOx emissions averaged over 30 days, and is projected to result in about 0.39 Δ dv in visibility improvement.

### III.C. Review of Particulate Matter Controls on the Kiln and Dryer

PM emissions from the kiln are currently controlled by fabric filter baghouse and wet dust suppression techniques. Emission testing from the kiln has demonstrated compliance with the National Emission Standards for Hazardous Air Pollutants for Source Categories; Portland Cement Manufacturing Industry, 40 CFR Part 63 Subpart LLL. The NESHAP standard applies the kiln and establishes PM emissions limits.

During development of the NESHAP standard, EPA was not able to identify any technologies for existing or new kilns that would consistently achieve lower emissions than the New Source Performance Standards (NSPS). Consequently, the level of the NESHAP standard is the same as NSPS and requires compliance with certain particulate emission limits and opacity limits. The NESHAP standard also includes emission limits for HCl and other hazardous pollutants; however these are not considered for their impact on visibility. The provisions of the NESHAP standard are already contained in the operating permit issued to Cemex – Lyons. For sources already regulated by a NESHAP standard, EPA stated the following in the BART guidelines:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the*

*MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART." [70 FR 39163]*

The Division has reviewed the requirements of the NESHAP (MACT) for Portland cement production and evaluated the RACT/BACT/LAER clearinghouse database for other available particulate control options (see Table 15). The Division has determined that no new particulate control methodologies are identified that would improve upon the PM controls required in the NESHAP.

Table 15: RACT/BACT/LAER data for PM emissions from Portland Cement Kilns

| | | | | |
|---|---|---|---|---|
| FL 0297 | Fabric Filter | 0.1 | lb/ton clinker | 2007 |
| MO-0072 | Baghouse | 0.516 | lb/ton clinker | 2006 |
| FL-0271 | Baghouse | 0.1 | lb/ton clinker | 2006 |
| FL-0268 | Baghouse | 0.2 | lb/ton clinker | 2004 |
| FL-0267 | ESP | 0.2 | lb/ton clinker | 2004 |
| SD-003 | Fabric Filter | 0.13 | lb/ton | 2003 |
| MO-0059 | Fabric Filter | 99% | | 2002 |
| IA-0052 | Baghouse | 0.5160 | lb/ton clinker | 2002 |
| TX-0355 | ESP | 40 | lb/hr | 2001 |
| FL-0139 | Baghouse | 0.11 | lb/ton clinker | 2000 |

Therefore, the Division is establishing the following PM and opacity limits as BART for particulate matter control that is based on the NESHAP 40 CFR Part 63 Subpart LLL:

Table 16: Particulate Matter Emission Limits on the Kiln and Dryer

| | | | |
|---|---|---|---|
| Kiln System | Fabric Filter Baghouse | 0.30 lb/ton of dry feed<br>20% opacity | 0.275 lb/ton of dry feed<br>20% opacity |
| Dryer | Fabric Filter Baghouse | 10% opacity | 22.8 tons/year*<br>10% opacity |

** Current emission limitation from Operating Permit (95OPBO082)*

The Division has established a PM limit on the kiln system that is more stringent than the NESHAP, which is already in the Cemex – Lyons Operating Permit. Because the current NESHAP limits constitute the most stringent level of control, the State does not need to provide a five-factor analysis for PM for these units.

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Colorado Energy Nations, Golden, Colorado**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Colorado Energy Nations Company (CENC) (formerly Trigen Colorado Energy Corporation) |
| Source Type: | Steam Generating Unit |
| Boiler Type(s): | Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)<br>Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal) |

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek to the south and US Highway 58 borders the northern side of the CENC site. The large building to the north of CENC and south of Highway 58 is the Coors Brewery.




**Figure 1: CENC facility Aerial Perspective**

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operated in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/$PM_{10}$ by separate

fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98$^{th}$ percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009 as well as additional information upon the Division's request on February 8, 2010 and May 7, 2010. These documents are all provided as "CENC BART Submittals". Table 1 depicts technical information for each BART-subject boiler at the CENC facility.

**Table 1: CENC Facility BART-eligible Emission Controls and Reduction (%)**

| | Unit B004 | Unit B005 |
|---|---|---|
| Placed in Service | 1975 | 1979 |
| Boiler Rating, MMBtu/Hr for coal | 360 | 650 |
| Electrical Power Rating, Gross Megawatts | 35 | 65 |
| Description | Combustion Engineering Model CE-VU40 360 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP | Combustion Engineering Model CE-VU40 650 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP |
| Air Pollution Control Equipment | Wheelabrator-Frye Model 264 fabric filter baghouse with 8 compartments | Carter Day fabric filter baghouse with 12 modules |
| Monitoring Equipment | COM<br>CEMs for $SO_2$, $NO_x$, $CO_2$, and stack gas | COM<br>CEMs for $SO_2$, $NO_x$, $CO_2$, and stack gas |

| | | |
|---|---|---|
| Emissions Reduction (%) | $NO_x$ – None<br>$SO_2$ – None<br>$PM/PM_{10}$ – 99+% | $NO_x$ – None<br>$SO_2$ – None<br>$PM/PM_{10}$ – 99+% |

## II. Source Emissions

CENC estimated that a realistic depiction of anticipated annual emissions for Boilers 4 and 5, or "Baseline Emissions", to be conservative, was the maximum historical (2000 – 2005) 12-month (rolling) emissions experienced in the July 31, 2006 analysis. CENC also provided 2-year annual average emissions for comparison purposes.

Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The baseline emissions are used as the basis for estimating annual emission reductions for the various control technologies evaluated and determining the annualized costs to achieve those reductions. . The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database as applicable. These emissions are summarized in Table 2.

**Table 2: CENC Boilers 4 and 5 Baseline Emissions**

| Pollutant | Boiler 4 | | Boiler 5 | |
|---|---|---|---|---|
| | Annual Emissions* (tpy) | 30-day rolling average emissions** (lb/MMBtu) | Annual Emissions* (tpy) | 30-day rolling average emissions** (lb/MMBtu) |
| $NO_x$ | 600 | 0.50 | 691 | 0.34 |
| $SO_2$ | 781 | 0.64 | 1,406 | 0.71 |
| $PM_{10}$ | 11 | 0.003*** | 18 | 0.01*** |

*Using most recent three calendar years (CEMs data).
**The Division calculated 30-day rolling average rate (lb/MMBtu) from the most recent three calendar years (CEMs data) based on maximum daily reported data for each unit for $NO_x$ and $SO_2$ emissions. Days with zero emissions/heat input were not included in these averages.
***The $PM_{10}$ emission rate is determined from calculating the maximum heat input and annual operating hours.

Boiler 4 is mainly fired on coal and can be fired on natural gas. Fuel oil may be used as a backup fuel, but has not been used in recent years. Boiler 5 is fired on coal, with backup oil firing. Either boiler also may fire ethanol or sludge from the Coors Brewery. Both units are subject to Colorado Regulation 6 Part A and NSPS 40 CFR Subpart D.

## III. Units Evaluated for Control

As documented by CENC, these boilers fire low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 3.

**Table 3: Coal Specifications (2006 – 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| B004 | 11,703 | 0.42 | 9.14 |
| B005 | 11,833 | 0.42 | 9.17 |

Table 1 lists the units at the CENC facility that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CEMs data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal.

**Table 4: Uncontrolled emission factors for CENC BART-eligible sources**

| Emission Unit | Pollutant | Fuel | | |
|---|---|---|---|---|
| | | Natural Gas (lb/MMscf) | Coal (bituminous) (lb/ton) | #2 Fuel Oil (lb/Mgallons) |
| Boiler 4 & Boiler 5 | $NO_x$ | 280 | 8.4 | 24 |
| | $SO_2$ | 0.6 | 35 x %S = 14.7* | 157 x %S = 67.5* |
| | $PM/PM_{10}$ | 7.6 | PM – 10 x %A = 91.4**<br>$PM_{10}$ – 2.3 x %A = 21.0** | PM – 2<br>$PM_{10}$ – 1 |

*%S = % of sulfur present in coal supply. For example, 35 x 0.42 = 14.7
**%A = % of ash present in coal supply. For example, 10 x 9.14 = 91.4

## IV. BART Evaluation of Boiler 4 and Boiler 5

### A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

CENC identified four $SO_2$ control options:
- Flue gas desulfurization (FGD):
  - Lime spray dry absorber (SDA or dry FGD)
- Dry sorbent injection – Trona (DSI)
- $SO_2$ emission management

The Division also identified and examined additional control options for these units:
- Lime or limestone-based (wet FGD)
- Emission limit tightening (no control)

Step 2: Eliminate Technically Infeasible Options

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

*Dry FGD:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[1]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling $SO_2$ Emissions: A Review of Technologies[2] evaluates various $SO_2$ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also bound the facility to the north and east. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with $SO_2$, the design gas residence time in a SDA is approximately 10 seconds. For Boilers 4 and 5, a SDA vessel for each boiler, not including other associated equipment, would be approximately 35 feet in diameter by 60 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on either Boilers 4 or 5 (B004/B005).

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential $SO_2$ controls on Units 4 and 5. The Division noted:

[1] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[2] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

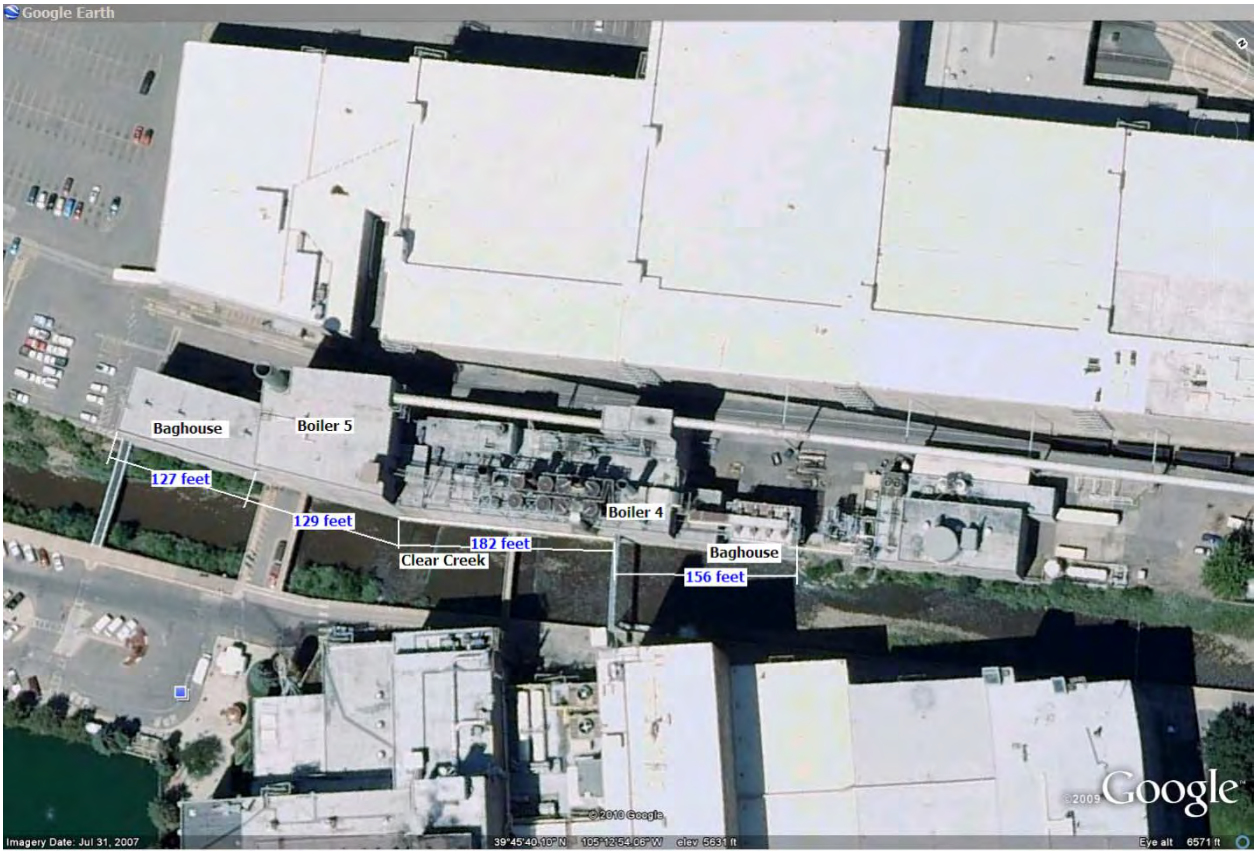



**Figure 2: Aerial Zoom of CENC Facility**

***DSI:*** Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the $SO_2$ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system.

However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, $NO_x$ to $SO_2$ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum $SO_2$ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum $SO_2$ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% $SO_2$ removal. In practical application, a higher $SO_2$ removal rate may be possible, while it is also possible that a lower $SO_2$ removal rate may be necessary to limit the brown plume formation. This determination would require actual $SO_2$ removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boilers 4 and 5.

***$SO_2$ Emissions Management:*** CENC is subjected to variations in as-received coal sulfur content. Figure 3 provided by CENC shows that there are clearly historical (2000 – 2005) short-term peaks in $SO_2$ emissions that can be attributed to infrequent deliveries of high-sulfur coal. CENC has no capability or additional storage space on site to store coal or to blend with other lower sulfur coals in order to manage $SO_2$ emissions to lower levels, and has not had a regulatory need to do so. Once delivered, the facility has no choice but to use the coal delivered before a subsequent lower sulfur shipment can be obtained and burned.

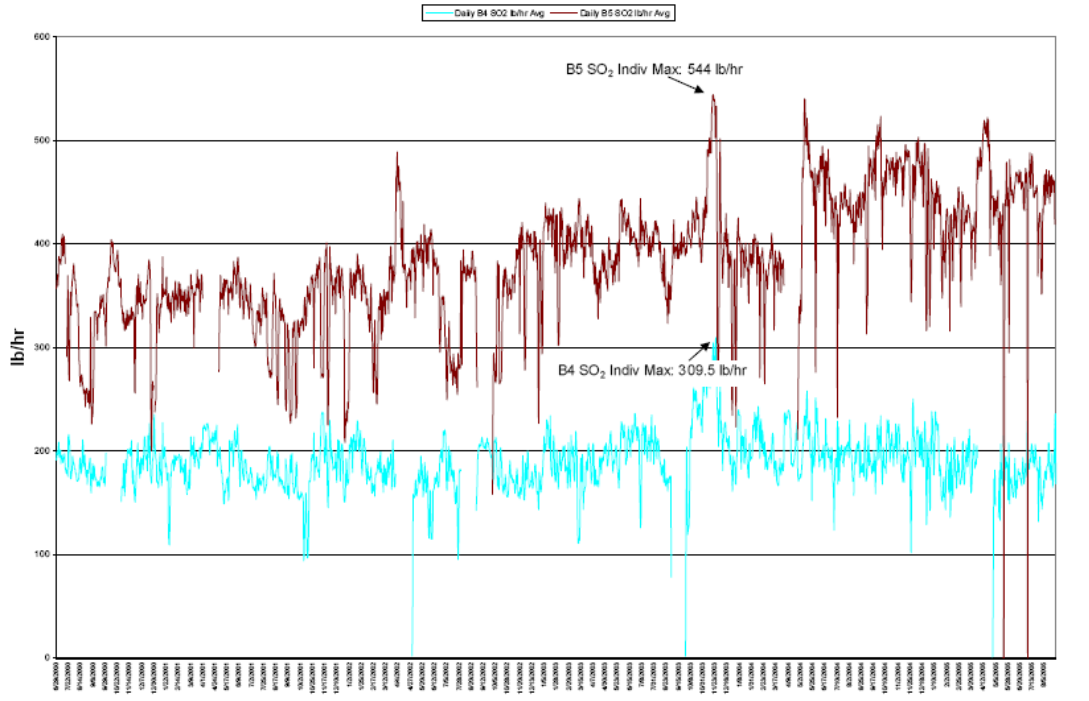



**Figure 3: Boilers 4 and 5 $SO_2$ lb/hour daily average (2000 - 2005)**

Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr $SO_2$ emissions. CENC can employ a variety of options to reduce emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak $SO_2$ limits. Since these two boilers already have CEMs and stack flow monitors installed, the CEMs could be used to demonstrate continuous compliance. CENC proposes reducing peak levels with limits at 280 lb/hr for Boiler 4 and 500 lb/hour for Boiler 5 on a 24-hour average basis. This option is technically feasible for Boilers 4 and 5.

*Emission limit tightening*: The Division and CENC conducted technical analyses of sulfur % and heat content in historical coal supplies to determine whether the current $SO_2$ emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for Boilers 4 and 5.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience, 30-day $SO_2$ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT $SO_2$ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details. The Division notes that for CENC, any RBLC determinations apply for DSI only, since $SO_2$ emissions management is unit-specific.

*DSI:* CENC asserts that the maximum $SO_2$ removal rate that can be achieved to be 65% $SO_2$ removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals[3] and to be conservative since this technology is relatively novel.

*$SO_2$ Emissions Management*: Table 5 summarizes current Title V permit limits and projected emission reductions using CENC's proposed limits.

[3] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

**Table 5: CENC Boiler 4 and 5 Current vs. Proposed $SO_2$ Permit Limits and Emissions Reduction**

| Unit | Current Title V $SO_2$ permit limits | Actual Emissions (2000 – 2005) | Actual Emissions (2006 – 2008) | CENC proposed $SO_2$ limits |
|---|---|---|---|---|
| Boiler 4 | 1892.0 tons/year (approx. 432 lb/hour) | 911.8 tons/year (approx. 208 lb/hour) | 780.6 tons/year (approx. 178 lb/hour) | 280 lb/hour (CEM 24-hr rolling avg.) |
| | Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.) | | | |
| | Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.) | | | |
| Boiler 5 | 3,416.0 tons/year (approx. 780 lb/hour) | 1,954.7 tons/year (approx. 446 lb/hour) | 1,406.0 tons/year (approx. 321 lb/hour) | 500 lb/hour (CEM 24-hr rolling avg.) |
| | Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.) | | | |
| | Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.) | | | |
| Combined limit | 4,888.0 tons/year (approx. 1,116 lb/hour) ($PM_{10}$ SIP Agreement) | 2,866.5 tons/year (approx. 655 lb/hour) | | 780 lb/hour (CEM 24-hr rolling avg.) |

*Refer to pages A-31, A-34, and A-35 of CENC BART Submittal (July 31, 2006) for detailed $SO_2$ emission documentation.

*Emission limit tightening:* Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) $SO_2$ emissions. The Division found that the maximum 30-day rolling emission rate was 0.80 lb/MMBtu for Boiler 4 and 0.9 lb/MMBtu for Boiler 5. However, for these small industrial boilers with very limited coal storage capacity, the Division and CENC agree that reviewing sulfur % and heat content is a better basis for determining an appropriate $SO_2$ emission limit. CENC submitted supplemental information on October 26 and November 10, 2010 to support this methodology. Refer to Table 6 for more details.

**Table 6: Coal Supply Analysis for SO2 Emission Limit**

| | 2006 – 2008 |
|---|---|
| Minimum (Btu/lb) | 9.997 |
| Maximum (% Sulfur) (30-day period) | 0.52 |
| Theoretical lb/MMBtu | |
| Boiler 4 Sulfur to $SO_2$ conversion averages at 99%* | 1.03 (rounded to 1.0) |
| Boiler 5 Sulfur to $SO_2$ conversion averages at 100%* | 1.04 (rounded to 1.0) |

*CEMs data vs. theoretical

Based on the boiler sulfur to $SO_2$ conversions, the appropriate emission limit based on actual fuel supply data for the baseline period is 1.0 lb/MMBtu (30-day rolling average). This option serves as assurance that CENC will be able to both continually comply with an appropriate emission limit while simultaneously eliminating future potential emission increases.

Table 7summarizes each available technology and technical feasibility for $SO_2$ control.

**Table 7: CENC Boilers 4 and 5 $SO_2$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|

| | | |
|---|---|---|
| Wet FGD | 52-98%, median 90%[4] | Y |
| Dry FGD (SDA) | 70-90% (CENC) | Y |
| DSI (Trona) | ~60% | Y |
| $SO_2$ Emissions Management | 30% | Y |
| Emission Limit Tightening | Minimal | Y |

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

*Wet FGD*: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

*DSI:* PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of $SO_2$ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of $SO_2$ collected. Detailed capital and annual cost data are presented in "CENC APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI, shown inTable 8.

**Table 8: DSI Cost Comparisons**

| Facility & Unit | Size (MW) | Annualized Costs ($/year) | Cost Effectiveness ($/ton) | Ratio ($/kW) |
|---|---|---|---|---|
| Colorado Energy Nations – Boiler 4 | 35 | $1,766,000 | $3,774 | $50.46 |
| Colorado Springs Utilities – Drake Unit 5 | 51 | $1,746,172 | $2,293 | $34.33 |

[4] U.S. EPA, 2000. "Controlling $SO_2$ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for the U.S. Environmental Protection Agency, Office of Research and Development. Office of Research and Development. Washington, D.C. 20460.

| | | | | |
|---|---|---|---|---|
| Colorado Energy Nations – Boiler 5 | 65 | $2,094,000 | $2,485 | $32.22 |
| Colorado Springs Utilities – Drake Unit 6 | 85 | $2,910,287 | $1,741 | $34.24 |

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[5] CENC Boiler 4 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

*$SO_2$ Emissions Management:* CENC notes that the costs for implementing a $SO_2$ Emission Management Plan are based on essentially zero capital cost with increment variable operating costs based on the replacement of a portion of coal boiler capacity with natural gas as needed to reduce historical 24-hour $SO_2$ peaks. The emission level projected for this alternative was derived from the analysis of historical emission level variability detailed in Figure 3.

The Division verified CENC's calculated costs for $SO_2$ Emission Management based on $SO_2$ hourly CEMs data (06/29/2000 through 01/04/2006), the amount of curtailment that will be required, and average natural gas costs ($10/MMBtu). In reviewing CENC's DSI estimate, the Division found that the ratio of annual costs to the total capital costs for the control technology option projected by CENC to be higher than those projected by other facilities that were amortized over the same 20 year time frame. The annualized costs for DSI are about 35% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[6]. However, CENC is a much smaller facility than the facilities in Arizona, New Mexico, and Oregon, which can significantly increase costs. CENC also clearly followed the Cost Control Manual methodology for estimating operation and maintenance costs. Therefore, the Division did not adjust CENC's cost estimates.

*Emission limit tightening:* There are no costs associated with this option. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 9, Table 10,Table 11, and Table 12 depict controlled $SO_2$ emissions and control cost comparisons.

**Table 9: Boiler 4 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 780 | 0.64 | 0.74 |

[5] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

[6] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

| | | | | |
|---|---|---|---|---|
| $SO_2$ Emissions Management | 0.13 | 767 | 0.64 | 0.74 |
| DSI - Trona | 60 | 312 | 0.26 | 0.30 |

**Table 10: Boiler 5 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,406 | 0.71 | 0.82 |
| $SO_2$ Emissions Management | 0.06 | 1,448 | 0.71 | 0.82 |
| DSI - Trona | 60 | 562 | 0.29 | 0.33 |

**Table 11: Boiler 4 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($)* | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| $SO_2$ Emissions Management | 1.0 | $44,299 | $43,690 | $43,089 |
| DSI - Trona | 468 | $1,766,000 | $3,744 | -$85 |

**Table 12: Boiler 5 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| $SO_2$ Emissions Management | 0.8 | $65,882 | $78,095 | $92,572 |
| DSI - Trona | 844 | $2,094,000 | $2,482 | -$90 |

Energy and Non-Air Quality Impacts

*Traditional Wet FGD:* Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's

domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[7]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART $SO_2$ control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of $SO_2$ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in $SO_2$ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

*$SO_2$ Emissions Management:* The Division has determined that there are not any negative energy or non-air quality related impacts related to the proposed $SO_2$ emission management scenario.

*DSI:* CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,[8] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

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[7] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[8] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

*Emission Limit Tightening*: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[9], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions (DSI control) at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 13: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| $SO_2$ Control Scenario | Unit(s) | $SO_2$ Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr | 4 | 0.90 | Rocky Mountain | 33 | --- | --- | 10 | --- | --- |
| | 5 | 0.98 | | | | | | | |

[9] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| DSI | 4 | 0.258 | National Park | 33 | 29 | 4 | 10 | 7 | 3 |
| | 5 | 0.286 | | 33 | 28 | 5 | 10 | 7 | 3 |
| Combo | 4&5 | 0.361<br>0.392 | | 33 | 3 | 30 | 10 | 0 | 10 |

**Table 14: Visibility Results – $SO_2$ Control Options**

| Scenario | Boiler(s) | $SO_2$ Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hr | 4<br>5 | 0.90<br>0.98 | 1.07 | --- | --- | --- |
| DSI | 4 | 0.258 | 0.99 | 0.08 | 8% | $21,802,469 |
| | 5 | 0.286 | 0.94 | 0.13 | 12% | $16,752,000 |
| Combo | 4<br>5 | 0.361<br>0.392 | 0.28 | 0.79 | 74% | $18,393,225 |

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ BART is the following $SO_2$ emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)
CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

## B. Filterable Particulate Matter ($PM_{10}$)

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control $PM/PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Conditions 3.5 and 4.4 require Boilers 4 and 5 to each meet a $PM/PM_{10}$ emission limit of 0.1 lb/MMBtu. Additionally, Condition 18.1 mandates that

each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 15 shows the most recent stack test data (August 23, 2007 for Boiler 4 and October 10, 2007 for Boiler 5). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

**Table 15: CENC 2007 Stack Test Results**

| Pollutant | Boiler 4 (lb/MMBtu) | Boiler 5 (lb/MMBtu) |
|---|---|---|
| Filterable $PM_{10}$ | 0.013 | 0.012 |
| $PM_{10}$ Control efficiency | 98.4% | 98.3% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

These boilers are subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[10] As currently proposed, the boilers will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[11]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible

[10] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
[11] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

(less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The Division has determined that an emission limit of 0.07 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for $PM/PM_{10}$ is not needed for CENC Boilers 4 and 5.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies

CENC identified four $NO_x$ control options:

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combustion modifications/low-$NO_x$ burners (LNB)
- Low-$NO_x$ burners + Separated Overfire Air (LNB+SOFA)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Fuel Switching – Natural Gas
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

*SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

CENC estimated that the retrofit SCR systems on Boilers 4 and 5 could achieve 0.06 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Units 4 and 5 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications,

adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case for the CENC boilers. Therefore, high-dust SCR is a technically feasible alternative for CENC Boilers 4 and 5.

*SNCR/SNCR+LNB/SOFA:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boilers 4 and 5.

*LNB/LNB+SOFA:* Low $NO_x$ burners are designed to control fuel and air mixing at each burner in order to create large and more branched flames. Peak flame temperature is thereby reduced, and results in less $NO_x$ formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Combustion, reduction and burnout are achieved in three stages within a conventional low $NO_x$ burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the $NO_x$ are formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed $NO_x$. In the third stage internal air staging completes the combustion but may result in additional $NO_x$ formation. This however can be minimized by completing the combustion in an air lean environment. Installing LNB with separated OFA may increase carbon monoxide (CO) emissions. LNB/LNB+SOFA are a technically feasible alternative for CENC Boilers 4 and 5.

Low $NO_x$ burners can be combined with other primary measures such as overfire air (OFA) or for even greater $NO_x$ emission reductions, separated overfire air (SOFA). The SOFA system diverts secondary air from the main windbox and injects it into the furnace above the main firing zone. This staged combustion process is one of the first principles of aggressive $NO_x$ reductions. LNB+SOFA is a technically feasible alternative for CENC Boilers 4 and 5.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[12] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[13] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boilers 4 and 5.

[12] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[13] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[14]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[15] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

*LNB/LNB+SOFA:* CENC estimated that low-$NO_x$ burners (Alstom's Low $NO_x$ Concentric Firing System (LNCFS) System) are capable of reducing $NO_x$ emissions by approximately 10 – 12%, which results in annual emission rates of 0.45 and 0.30 lb/MMBtu for Boilers 4 and 5, respectively. A similar Colorado facility with installed LNB achieves approximately 0.35 – 0.38 lb/MMBtu and estimates an additional 20% reduction if OFA is installed to achieve 0.28 – 0.30 lb/MMBtu. These same burners with Separated Overfire Air were estimated to reduce $NO_x$ emissions by 19 – 35%, resulting in an annualized estimated 0.32 and 0.28 lb/MMBtu for Boilers 4 and 5 respectively.

EPA's AP-42 emission factor tables estimate low-$NO_x$ burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of $NO_x$ emissions.[16] A recent AWMA study noted that LNB with close-coupled OFA firing bituminous coal in tangentially fired boilers achieved, on average, 35% $NO_x$ reduction.[17] However, due to the size and configuration (e.g. furnace dimensions) of the CENC boilers, the Division concurs that the estimated control efficiency rates are reasonable.

*SNCR/SNCR+LNB/SOFA:* CENC noted in the original BART submittal (July 2006) that SNCR achieves 30 – 50% control, which is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet and the Division's experience. However, when CENC calculated SNCR control efficiency in the November 2009 submittal, it was assumed that LNB+SOFA would be installed beforehand. CENC estimated that SNCR would reduce $NO_x$ emissions 40% with LNB+SOFA installed, for resultant emission rates of 0.19 lb/MMBtu and 0.17 lb/MMBtu for Boilers 4 and 5, respectively. This equates to 62 – 67% reduction depending on the boiler, which

[14] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[15] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

[16] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[17] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

is consistent with EPA's AP-42 emission factor tables (50 – 80%).[18] Therefore, the Division concurs with CENC's control efficiency estimates for LNB+SOFA+SNCR.

The Division conducted a separate analysis regarding stand-alone SNCR installation (without LNB+SOFA installation) for comparison purposes. The Division did not use CENC's original estimate of 40% reduction for SNCR. Instead, the Division estimated control efficiency based on a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[19] to conservatively approximate that the CENC boilers can achieve 30% control when SNCR is applied.

*SCR:* CENC, via their vendor, estimates that each boiler will be able to achieve a 0.06 lb/MMBtu emission rate on a 30-day rolling average. CENC estimated control efficiencies on the assumption that LNB+SOFA will already be installed. However, this will not change the overall SCR resultant emission rate.

The Division adjusted this emission rate to be 0.07 lb/MMBtu to be consistent with other Colorado facility submittals and literature review. This adjusted rate equates to 86% control for Boiler 4 and 80% control for Boiler 5. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[20,21] Table 16 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 16: CENC Boilers 4 and 5 $NO_x$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners (LNB) | 35 – 55% | Y |
| LNB + OFA | 40 – 60% | Y |
| Overfire air (OFA) | 10 – 25% (alone) | Y |
| Selective non-catalytic reduction (SNCR) | ~30 - 50% | Y |
| SNCR+LNB+SOFA | ~50 – 80% | Y |
| Selective catalytic reduction (SCR) | ~75 – 90% | Y |
| ECO® | n/a | N |
| RRI | n/a | N |
| Coal reburn +SNCR | n/a | N |

Step 4: Evaluate Impacts and Document Results

[18] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[19] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

[20] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[21] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Cost of Compliance

*LNB/LNB+SOFA:* CENC contracted Alstom Power to determine total installed costs for low-$NO_x$ burners and separated overfire air. Factors from EPA's Cost Control Manual were used to develop the total annual cost estimate. EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing CENC's estimates, the Division found that the ratio of annual costs to the total capital costs for LNB/LNB+SOFA projected by CENC to be slightly higher than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for LNB for Boilers 4 and 5 are 16.1% and 15.5%, respectively, of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[22]. However, the Division and CENC note that the boilers are much smaller than those examined by the EPA. Therefore, the Division concurs with CENC's cost estimates for LNBs. Further, the Division compared recent NESCAUM studies estimating LNB+SOFA for tangentially-fired boilers as between $420 - $1,600 per ton $NO_x$ reduced.[23] Both the original and revised CENC cost effectiveness estimates are within the NESCAUM ranges, providing further verification that cost estimates are reasonable. The NESCAUM study did not provide cost estimate ranges for LNB on tangentially-fired boilers.

*SNCR/SNCR+LNB+SOFA:* The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the CENC boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[24] The CENC-estimated SNCR costs for operating expenses are 81% and 86% for Boiler 4 and Boiler 5, respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[25]

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[22] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.
[23] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[24] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[25] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Boilers 4 and 5 is about $2,900 and $3,350 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[26,27] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[28] Although CENC's estimates are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SNCR are reasonable.

*SCR:* CENC contracted Lutz, Daily, & Brain (LDB) to develop a capital cost estimate. On both boilers, it was determined that the economizers must be moved because there is very little space between the air heater outlet and the current economizer configuration, adding to the capital cost.

Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[29,30] CENC's cost estimates are higher than this range, but the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SCR are reasonable.

Table 17, Table 18, Table 19, and Table 20 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 17: CENC Boiler 4 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | | | |
|---|---|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) | Annual Average (lb/hour) | 30-day Rolling Average (lb/hour) |
| Baseline | --- | 599 | 0.50 | | 179 | |
| LNB | 10 | 539 | 0.45 | 0.515 | 161 | 185 |
| SNCR | 30 | 420 | 0.35 | 0.400 | 125 | 144 |
| LNB+SOFA | 35 | 390 | 0.32 | 0.372 | 116 | 134 |
| SNCR+LNB+SOFA | 61 | 231 | 0.192 | 0.221 | 69 | 79 |
| SCR | 86 | 84 | 0.070 | 0.080 | 25 | 29 |

[26] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[27] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[29] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[30] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

**Table 18: CENC Boiler 5 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | | | |
|---|---|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) | Annual Average (lb/hour) | 30-day Rolling Average (lb/hour) |
| Baseline | --- | 691 | 0.34 | | 165 | |
| LNB | 7 | 643 | 0.32 | 0.368 | 153 | 176 |
| LNB+SOFA | 18.5 | 563 | 0.28 | 0.322 | 134 | 155 |
| SNCR | 30 | 484 | 0.24 | 0.277 | 115 | 133 |
| SNCR+LNB+SOFA | 51 | 337 | 0.17 | 0.193 | 80 | 93 |
| SCR | 79.6 | 141 | 0.07 | 0.081 | 34 | 39 |

**Table 19: CENC Boiler 4 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| LNB | 59.9 | $193,433 | $3,227 | $54 |
| SNCR | 179.8 | $694,046 | $3,860 | $5 |
| LNB+SOFA | 209.8 | $678,305 | $3,234 | -$21 |
| SNCR+LNB+SOFA | 368.0 | $1,372,351 | $3,729 | $3 |
| SCR | 515.4 | $4,201,038 | $8,150 | $30 |

**Table 20: CENC Boiler 5 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| LNB | 48.4 | $249,858 | $5,166 | $107 |
| LNB+SOFA | 127.3 | $815,829 | $6,383 | $15 |
| SNCR | 207.3 | $923,996 | $4,458 | ($24) |
| SNCR+LNB+SOFA | 353.7 | $1,739,825.3 | $4,918 | $3 |
| SCR | 550.0 | $6,469,610 | $11,764 | $35 |

Energy and Non-Air Quality Impacts

*LNB/LNB+SOFA:* Installing LNB with separated OFA may increase unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Otherwise, there are no known non-air quality

impacts associated with low-$NO_x$ burners and separated overfire air systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/SNCR+LNB+SOFA/SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the case of the CENC boilers, 90 kW per hour, or enough energy to power about 9 homes for a year, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For CENC Boilers 4 and 5, the estimated pressure drop across the catalyst is 7 to 8 inches water column and the total energy consumption is approximately 1,000 kW per hour, or enough energy to power about 100 homes for a year.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to "CENC BART Submittals" for more information.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 21 shows the number of days pre- and

post-control. Table 22 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[31], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 21: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr | 4 | 0.67 | Rocky Mountain National Park | 33 | --- | --- | 10 | --- | --- |
| | 5 | 0.66 | | | | | | | |
| LNB | 4 | 0.45* | | n/a | | | | | |
| | 5 | 0.30* | | n/a | | | | | |
| SNCR | 4 | 0.35* | | n/a | | | | | |
| | 5 | 0.24* | | n/a | | | | | |
| LNB+SOFA | 4 | 0.32 | | 33 | 27 | 6 | 10 | 7 | 3 |
| NOx Modeled Rate | 5 | 0.28 | | 33 | 25 | 8 | 10 | 6 | 4 |
| LNB+SOFA | 5 | 0.24* | | n/a | | | | | |
| LNB+SOFA+SNCR | 4 | 0.19 | | 33 | 27 | 6 | 10 | 7 | 3 |
| | 5 | 0.17 | | 33 | 19 | 14 | 10 | 6 | 4 |
| SCR @ 0.07 lb/MMBtu | 4 | 0.07 | | 33 | 25 | 8 | 10 | 6 | 4 |
| SCR @ 0.07 lb/MMBtu | 5 | 0.07 | | 33 | 19 | 14 | 10 | 6 | 4 |

[31] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Combo | 4<br>5 | 0.07<br>0.07 | | 33 | 3 | 30 | 10 | 0 | 10 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

**Table 22: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hr | 4<br>5 | 0.67<br>0.66 | 1.07 | --- | --- | --- |
| LNB | 4 | 0.45* | 1.02 | 0.05 | 5% | $3,868,660 |
| | 5 | 0.30* | 0.89 | 0.17 | 16% | $1,435,965 |
| SNCR | 4 | 0.35* | 0.99 | 0.07 | 7% | $9,507,477 |
| | 5 | 0.24* | 0.86 | 0.21 | 20% | $4,358,471 |
| LNB+SOFA | 4 | 0.32 | 0.99 | 0.08 | 7% | $8,478,816 |
| NOx Modeled Rate | 5 | 0.28 | 0.88 | 0.18 | 17% | n/a |
| LNB+SOFA | 5 | 0.24* | 0.86 | 0.21 | 20% | $3,848,252 |
| LNB+SOFA+SNCR | 4 | 0.19 | 0.96 | 0.11 | 10% | $12,475,919 |
| | 5 | 0.17 | 0.82 | 0.25 | 23% | $7,101,328 |
| SCR @ 0.07 lb/MMBtu | 4 | 0.07 | 0.89 | 0.18 | 17% | $23,734,677 |
| SCR @ 0.07 lb/MMBtu | 5 | 0.07 | 0.75 | 0.31 | 29% | $20,669,680 |
| Combo | 4<br>5 | 0.07<br>0.07 | 0.28 | 0.79 | 74% | $18,393,225 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

Step 6: Select BART Control

The Division and CENC worked together to determine a "flexible" BART option for Boilers 4 and 5. CENC initially proposed this option in its' prehearing statement on September 15, 2010. This option incorporates both an individual limit (lb/MMBtu) for each boiler or a combined average (lbs/hr) for both boilers for a 30-day rolling average period. CENC submitted supplemental information regarding a "flexible" BART plan on October 19, 2010 to the Division, citing the preamble to the BART regulations to 'consider allowing sources to 'average' emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible source." This determination adheres to the language in the BART preamble.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

Based upon its consideration of the five factors summarized herein, the state has determined that $NO_x$ BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Public Service Company – Comanche Station, Units 1 and 2**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Public Service Company |
| Source Type: | Electric Utility Steam Generating Unit |
| SCC (EGU): | Unit 1: 10100226 Unit 2: 10100222 |
| Boiler Type: | Three Dry-Bottom Pulverized Coal-Fired Boilers, two tangentially fired (Units 1 and 3) and one wall-fired (Unit 2) |

Comanche Station is located at 2005 Lime Road in Pueblo, CO, which is located within Pueblo County. Comanche Station commenced operation in the early 1970s. The facility originally consisted of two coal fired boilers, driving steam turbines used to generate electricity and associated support equipment (cooling and service water towers and coal and ash handling equipment). Unit 1 commenced operation in 1972 and serves a generator rated at 325 MW. Unit 2 commenced operation in 1975 and serves a generator rated at 335 MW. The boilers burn sub-bituminous coal from the Powder River Basin (PRB) as fuel and use natural gas for startup, shutdown and flame stabilization.

In August of 2004, Public Service Company of Colorado (PSCo) proposed to construct and operate a new coal-fired boiler (Unit 3) at Comanche Station. As part of that project, PSCo proposed to install control devices on the existing units. PSCo entered into a Settlement Agreement in December 2004 with various citizen groups and voluntarily agreed to install additional control devices and take emission limitations. In addition to the new unit (Unit 3), additional support equipment was proposed including a cooling tower, coal and ash handling equipment and various support equipment for the control device reagents (e.g., silos for lime, recycle ash and sorbent). Construction permits for the project were issued on July 5, 2005.

Low $NO_X$ burners with over-fire air and a lime spray dryer were installed in November 2008 on Unit 1 and low $NO_X$ burners with over-fire air and a lime spray dryer were installed in November 2007 on Unit 2. Operation of the $SO_2$ controls did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. Unit 3 commenced operation in January 2010.

Units 1 and 2 are considered BART-eligible because the units were in existence on August 7, 1977 and not in operation prior to August 7, 1962 and are located at a fossil-fuel-fired steam electric plant greater than 250 MMBtu/hr, with the potential to emit of more than 250 tons or more of any visibility impairing air pollutant ($NO_X$, $SO_2$, $PM_{10}$). The results of the initial BART modeling analysis, indicated that the visibility impairment exceeded 0.5 deciviews (98% percentile -

8th high), at federal Class I areas. Therefore, since Units 1and 2 "cause or contribute" to visibility impairment BART applies to these units.

Table 1 below lists the units at Public Service Company Comanche Station that are subject to BART and are addressed in this BART analysis as well as the control efficiency of the controls currently installed on Units 1 and 2 (note $SO_2$ and $NO_X$ controls were installed within the baseline period).

**Table 1: Comanche Units 1 and 2 Technical Information**

| | Unit 1 | Unit 2 |
|---|---|---|
| Placed in Service | December 1973 | November 1975 |
| Boiler Rating, MMBtu/Hr for coal | 3,531 | 3.482 |
| Electrical Power Rating, Gross Megawatts | 325 | 335 |
| Description | Combustion Engineering Tangentially Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization. | Babcock and Wilcox Wall-Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization. |
| Air Pollution Control Equipment | $PM/PM_{10}$ – Baghouse – Installed 1993<br>$NO_X$ – Low $NO_X$ Burners with Over-Fire Air – Installed November 2008<br>$SO_2$ – Lime Spray Dryer – Installed November 2008, fully operational 6/3/09 | $PM/PM_{10}$ –Baghouse – Installed 1991<br>$NO_X$ – Low $NO_X$ Burners with Over-Fire Air - Installed November 2007<br>$SO_2$ – Lime Spray Dryer – Installed November 2007, fully operational 1/10/09 |
| Emissions Reduction (%)* | $NO_X$ – 62.7%<br>$SO_2$ – 76.1%<br>PM – 99.7%<br>$PM_{10}$ – 99.0% | $NO_X$ – 44.1%<br>$SO_2$ – 81.9%<br>PM – 99.8%<br>$PM_{10}$ – 99.3% |

*Emissions Reduction estimated by comparing pre-control 2005 – 2007 CAMD data (2005 – 2006 for $NO_x$ on Unit 2) to controlled 2009 data. For $PM/PM_{10}$., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Comanche APCD Technical Analysis" for further details. Not based on actual testing.

PSCo submitted a BART analysis to the Division on August 1, 2006, with revisions to that analysis submitted on August 15, 2006 (editorial corrections), October 19, 2006 and January 8, 2007. At the Division's request, PSCo submitted additional information dated January 19, February 24, March 1, April 12, April 21, May 25, July 14, and July 22, 2010. These documents are included as "PSCo BART Submittals".

## II. Source Emissions

In PSCO's August 1, 2006 BART application, baseline emissions were based on calendar year 2004 and 2005 emissions. Several years have passed since the

original BART submittal, in which the Division has updated modeling and technical analyses. Additionally, PSCo, as detailed in Table 1, has installed air pollution controls on both units at Comanche in 2008. Therefore, the Division used years 2009 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database.

Controls were installed on Unit 2 in November 2007 and controls were installed on Unit 1 in November 2008. While the $SO_2$ controls did not commence full operation until 2009, the $NO_X$ controls did commence operation upon installation. In addition, PSCo has indicated that lime was initially injected into the lime spray dryers in December 2008 for Unit 1 and July 2008 for Unit 2 in order to test the controls. The baseline emissions are summarized in Table 2.

**Table 2: PSCo Comanche Units 1 & 2 Baseline Emissions**

| Pollutant | Unit 1 | | Unit 2 | |
|---|---|---|---|---|
| | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) |
| $NO_x$ | 1,511 | 0.124 | 2,349 | 0.165 |
| $SO_2$ | 1,557 | 0.128 | 1,244 | 0.091 |
| $PM_{10}$ | 80 | 0.007*** | 40 | 0.005*** |

*Using daily CEMs data from 2009 calendar year (CAMD data).
**The Division calculated average emission rate or used the CAMD reported rate (lb/MMBtu) from the 2009 calendar year (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions.
***The $PM_{10}$ emission factor is determined from the most recent Title V permit compliance stack tests (March 2003).

## III. Units Evaluated for Control

According to PSCo's August 1, 2006 BART application sub-bituminous coal from the Powder River Basin (PRB), Belle Ayr mine in Wyoming is typically used as fuel. The characteristics of the Belle Ayr PRB coal presented in the August 1, 2006 BART application are presented below in Table 3.

**Table 3: Comanche Station Coal Specifications (From August 1, 2006 BART Application)**

| | |
|---|---|
| Coal Mine/Region | PRB – Belle Ayr |
| Coal Rank Classification | Sub-bituminous |
| **Proximate Analysis** | |
| $H_2O$ (Moisture weight %) | 29.9 |
| Ash (weight %) | 4.6 |
| Sulfur (weight %) | 0.31 |
| **Ultimate Analysis** | |
| Nitrogen (weight percent %) | 0.68 |
| **Other** | |
| Heating Value (HHV Btu/lb) | 8,550 |

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

**Table 4: Uncontrolled emission factors for Comanche BART-eligible sources[1]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Unit 1 | 8.4 | 9.5 | 46.6 | 10.7 |
| Unit 2 | 7.4 | 9.5 | 46.6 | 10.7 |

*$SO_2$ and $PM/PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006-2009). Please refer to "Comanche APCD Technical Analysis" for more details.

Emission limitations that apply to these boilers are as follows:

- Colorado Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu, for each boiler.
- Colorado Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu, for each boiler.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits $NO_X$ emissions to 0.40 lb/MMBtu and 0.46 lb/MMBtu, both on an annual average basis for Units 1 and 2, respectively.
- 40 CFR Part 60 Subpart D §§ 60.44(a)(3) and 60.45(g)(3), as adopted by reference in Colorado Regulation No. 6, Part A limits $NO_X$ emissions to 0.7 lb/mmBtu, on a 3-hr rolling average. Applies to Unit 2 only.
- Colorado Construction Permits 11PB859, IA, mod 1 (Unit 2) and 04PB1429, IA (Unit 1) both issued July 5, 2005)
  - $NO_X$ emissions shall not exceed 0.20 lb/MMBtu, on a 30-day rolling average, for each unit.
  - $SO_2$ emissions shall not exceed 0.12 lb/MMBtu, on a 30-day rolling average, for each unit.

  These limits shall be met no later than 180 days after the initial startup of the $SO_2$ and $NO_X$ control equipment for each unit or by July 1, 2009, whichever is earlier
  - $NO_X$ emissions from both Units 1 and 2 together shall not exceed 0.15 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)
  - $SO_2$ emissions from both Units 1 and 2 together shall not exceed 0.10 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)

  PSCo shall begin calculating compliance with these limits no later than 180 days after initial startup of the $SO_2$ and $NO_X$ control equipment for the last unit.
  - Filterable PM emissions shall not exceed the following limits: Unit 1: 393 tons/quarter and 1,546 tons/yr and Unit 2: 390 tons/quarter and 1,525 tons/yr.

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

- Filterable $PM_{10}$ emissions shall not exceed the following limits: Unit 1: 363 tons/quarter and 1,423 tons/yr and Unit 2: 357 tons/quarter and 1,403 tons/yr.
- $SO_2$ emissions from Units 1 and 2 together shall not exceed 939.3 tons/quarter and 3,686 tons/yr.
- $NO_X$ emissions from Units 1 and 2 together shall not exceed 1,564.4 tons/quarter and 6,142 tons/yr.

The above limitations take effect 180 days after initial startup of the last control device for the last unit or upon startup of Unit 3, whichever is earlier. Note that the quarterly limits apply for the first year of operation only.

## IV. BART Evaluation of Units 1 and 2

### A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Comanche Units 1 and 2 if technically feasible. These upgrades include:
-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system

The current Construction Permit limits are depicted in Table 5.

**Table 5: Comanche Units 1 & 2 $SO_2$ Operating Permit Limits**

| | $SO_2$ limits (lb/MMBtu) | |
|---|---|---|
| | 30-day rolling | Annual rolling (combined) |
| Units 1 & 2 | 0.12 | 0.10 |

As indicated in EPA's BART Guidelines [70 FR 39171], for dry-FGD (i.e., LSDs) the following scrubber upgrades should be considered.

- Use of performance additives

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

In addition to upgrades to the scrubbers, the Division also asked PSCo to look into the feasibility of achieving a lower 30-day $SO_2$ emission limitation with the existing controls (i.e., $SO_2$ emission limit tightening) and/or other potential upgrades, including improved operations and maintenance, use of more reagent, and keeping more spare parts on hand.

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an $SO_2$ upgrade analysis to the Division on May 25, 2010 and additional information on July 22, 2010 regarding potential upgrades for the LSDs installed on Comanche Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Dry FGD Upgrades:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

As indicated previously, as part of a permitting action to construct and operate a new unit (Unit 3) at Comanche Station, PSCo committed to installing both $NO_X$ and $SO_2$ controls on Units 1 and 2. Permits were issued on July 5, 2005 for Units 1 and 2 which addressed the controls and the associated emission limitations that these units would be required to meet prior to commencing operation of the proposed new unit. To that end, a lime spray dryer (LSD) was installed on Unit 1 in November 2008 and a LSD was installed on Unit 2 in November 2007. Full operation of the LSDs commenced in June 2009 and January 2009 for Units 1 and 2, respectively. Table 1indicates that the LSDs are achieving

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

emission reductions at approximately 76% for Unit 1 and 82% for Unit 2 in comparison with the permit limits[4] depicted in Table 5. It should be noted that since July 1, 2009, when the $SO_2$ limits became applicable, Unit 1is achieving emission reductions at about 86.5% and Unit 2 at 85.3%. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits. Therefore, since Comanche Units 1 and 2 are equipped with existing FGD and are achieving removal efficiencies greater than 50%, the BART analysis need not consider replacement of the $SO_2$ controls but should consider upgrades to the existing FGD.

-*Use of performance additives:* The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous $SO_2$. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same $SO_2$ reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in $SO_2$ removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal. Therefore, this upgrade is not technically feasible. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase $SO_2$ removal and therefore warrants no further consideration.

-*Use of more reactive sorbent:* All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Hayden.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove $SO_2$. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied

[4] Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

by Rockwell and used rotary atomizers. The unit was designed to obtain 70% $SO_2$ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to $NO_2$ due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO2 removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes $SO_2$ removal; there are no known acceptable reagents without side effects that would allow additional $SO_2$ removal in the dry scrubbing systems present at Comanche Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

*Increase the pulverization level of sorbent:* PSCo indicated that Colorado's dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. Although PSCo notes that there have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. Their experience has been that there is no $SO_2$ removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. PSCo considers that they already uses the best available grinding technologies and that there are no improvements that can be done to further decrease lime particle size to reduce $SO_2$ emissions. The Division agrees that upgrades to grinding technologies are unlikely to produce additional $SO_2$ reductions and therefore no further consideration is warranted.

*Engineering redesign of atomizer or slurry injection system:* The Comanche dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both $SO_2$ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve $SO_2$ removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved $SO_2$ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the $SO_2$ removal level, although some have improved wear life and reduced maintenance costs. Given that the LSDs installed on Units 1 and 2 were installed recently, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher $SO_2$ removal.

*Emission limit tightening*: In addition to considering upgrades to the existing FGDs on Units 1 and 2, the Division asked PSCo to consider whether tightening of the existing BART 30-day limits was feasible. Comanche Units 1 and 2 are subject to the following $SO_2$ emission limitations:

**Table 6: Comanche Units 1 & 2 $SO_2$ Emission Limitations**

| | SO2 Emission Limitations | | | | |
|---|---|---|---|---|---|
| | Emission Rate (lb/MMBtu) | | | Mass Emissions (tons) | |
| | 3-hr rolling | 30-day rolling* | 365-day rolling | Quarterly | Annual |
| Unit 1 | 1.2 | 0.12 | N/A | N/A | N/A |
| Unit 2 | 1.2 | 0.12 | N/A | N/A | N/A |
| Units 1 and 2 Together | N/A | N/A | 0.10 | 939 | 3.686 |

*Included as limits in the BART construction permit (07PB0112B) issued September 12, 2008.

In their May 25, 2010 submittal, PSCo addressed the feasibility of tightening their 30-day $SO_2$ emission limits. In their submittal, PSCo indicated that based on operating experience for Comanche Units 1 and 2, as well as other PSCo units equipped with LSDs, that the primary factor affecting the $SO_2$ control efficiency for short-term averages are startups, equipment malfunctions and low load operations. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below the minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. PSCo indicated that this had actually occurred while operating Comanche Unit 2 and Valmont Unit 5 and resulted in extended maintenance outages in order to clean the scrubbers. In addition, during unit start-ups, it can take anywhere from between 12 and 24 hours to get the inlet scrubber temperature up to the level necessary for safe slurry injection. The scrubber can be run at higher levels of $SO_2$ reduction in order to offset the effects of a startup during a 30-day period, but the more startups that occur during that 30 day permit the more difficult it will become to offset the higher emissions during startup. PSCo also indicated that during low load operations, especially in the winter, the inlet temperature at the baghouse approaches the minimum acceptable level, subsequently lowering the overall $SO_2$ control efficiency during low load operations. PSCo indicated that due to the increased use of wind resources, the boilers will be required to cycle more frequently to accommodate intermittent wind resources and therefore, the units will run at low loads more frequently and as a result the $SO_2$ reduction levels will be lower during those times.

The Division reviewed available $SO_2$ emission data from CAMD for 2009 and for part of 2010 (January – October 2010). As previously indicated although the LSDs were installed in 2007 and 2008, they only recently commenced full operation, Unit 1 in June 2009 and Unit 2 in January 2009. As a result there is limited data available to determine post-control achievable emissions. In addition, if as PSCo indicates, the units are cycled more frequently to accommodate increased wind energy resources, it is not clear how well the data represents future operation. In addition, since the LSDs came on line recently, PSCo has limited operating experience with these units. Although PSCo has

other units that are equipped with LSDs and have been operating those units with LSDs for some time (e.g., Valmont Unit 5, Hayden Units 1 and 2), those units are not using PRB coal. Comanche Units 1 and 2 represent the first units in PSCo's system with LSDs that are firing PRB coal as fuel. After startup of the LSDs in 2009 both units have had a number of days indicating zero emissions, presumably due to a unit shutdown. In addition, in many cases, emissions data shows that frequently for one or more days following these events, the daily $SO_2$ emission rate is well above 0.12 lb/MMBtu. Unit 1 averaged 0.07 lb/MMBtu during this period, with a maximum rate of 0.10 lb/MMBtu in December 2009. Unit 2 has had several months (December 2009, May 2010, October 2010) during the 2009 – 2010 timeframe that either exceed or are within 0.01 lb/MMBtu of the existing 0.12 lb/MMBtu 30-day rolling average limit. A review of annual data showed that in 2009, the $SO_2$ annual average from both units was approximately 0.11 lb/MMBtu. In 2010 thus far, the annual average is 0.07 lb/MMBtu, but it is important to note that it is apparent from the data on both units historically that lower inlet temperature(s) to the scrubber(s) in the winter months result in increased $SO_2$ emissions.

As explained above, the Division projects 30-day rolling $SO_2$ emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer or greater to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy. Therefore, the Division concurs that tighter 30-day rolling average and annual average $SO_2$ emission limit is not feasible at this time for either unit.

*Additional equipment and maintenance:* As discussed in the emission limit tightening section, PSCo reviewed actual operating experience on Comanche along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect $SO_2$ control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, $SO_2$ emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control $SO_2$ by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum

acceptable levels, thus lowering overall $SO_2$ control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

PSCo sent confirmation to the Division on July 22, 2010 that an extra scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers. The Division concurs with this assessment. Therefore, since it is not technically feasible to install an extra scrubber module, additional spare atomizer parts and increased operating and maintenance will not result in decreased $SO_2$ emissions. The Division concludes that this option is not technically feasible for Comanche Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased $SO_2$ reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct a control effectiveness evaluation.

Step 4: Evaluate Impacts and Document Results

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased $SO_2$ reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct an evaluation of the cost, energy and non-air environmental impacts, and remaining useful life.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various potential emission rates. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 6 shows the number of days pre- and post-control. Table 7 depicts the visibility results ($98^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[5], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants ($NO_x$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-

[5] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

**Table 6: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Unit(s) | SO2 Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1<br>2 | 0.75<br>0.74 | Great Sand Dunes National Park | 60 | --- | --- | 27 | --- | --- |
| Dry FGD | 1 | 0.12 | | 60 | 49 | 11 | 27 | 21 | 6 |
| | 2 | | | 60 | 50 | 10 | 27 | 21 | 6 |
| Dry FGD | 1 | 0.10 | | 60 | 48 | 12 | 27 | 21 | 6 |
| | 2 | | | 60 | 49 | 11 | 27 | 21 | 6 |
| Dry FGD | 1 | 0.08* | | n/a | | | | | |
| | 2 | | | n/a | | | | | |
| Dry FGD | 1 | 0.07 | | 60 | 48 | 12 | 27 | 20 | 7 |
| | 2 | | | 60 | 48 | 12 | 27 | 21 | 6 |
| Combo | 1<br>2 | 0.12 | | 60 | 4 | 56 | 27 | 1 | 26 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

**Table 7: Visibility Results – $SO_2$ Emission Rates**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact)* | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) |
| Max 24-hour | 1<br>2 | 0.75<br>0.74 | 2.05 | --- | --- |
| Dry FGD | 1 | 0.12 | 1.71 | 0.35 | 17% |
| | 2 | | 1.72 | 0.33 | 16% |
| Dry FGD | 1 | 0.10 | 1.69 | 0.36 | 17% |
| | 2 | | 1.71 | 0.35 | 17% |
| Dry FGD | 1 | 0.08* | 1.68 | 0.37 | 18% |

| | | | | | |
|---|---|---|---|---|---|
| | 2 | | 1.69 | 0.36 | 18% |
| Dry FGD | 1 | 0.07 | 1.67 | 0.38 | 18% |
| | 2 | | 1.69 | 0.37 | 18% |
| Combo | 1 | 0.12 | 0.36 | 1.69 | 82% |
| | 2 | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ BART is the following existing $SO_2$ emission rates:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling $SO_2$ limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

## B. Filterable Particulate Matter ($PM_{10}$)

Comanche Units 1 and 2 are each equipped with fabric filter baghouses to control PM/$PM_{10}$ emissions. In a baghouse, the particle laden flue gas passes through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow. The bags are periodically cleaned when too much filter cake builds up and increases the pressure drop across the fabric filter. A baghouse is considered the best particulate matter control device particularly for boilers burning low sulfur western coals.

As indicated previously in Table 1, estimated control efficiencies for the baghouse are over 99% for both PM $PM_{10}$. These control efficiencies are based on the allowable post-control emissions rate of 0.1 lb/MMBtu for PM and 0.092 lb/MMBtu for $PM_{10}$ (assumes $PM_{10}$ = 92% of PM). Actual performance test data shown in Table 8 indicates that PM emissions from Comanche Units 1 and 2 are well below the allowable levels. The results of performance tests conducted in 2003 indicate the following emission rates:

**Table 8: Comanche Units 1 and 2 Stack Test Results (2003)**

| Pollutant | Unit 1 (lb/MMBtu) | Unit 2 (lb/MMBtu) |
|---|---|---|
| Filterable $PM_{10}$* | 0.003 | 0.003 |
| $PM_{10}$ Control efficiency | 99.6% | 99.6% |

*$PM_{10}$ = 0.92 x PM

The BART construction permit (07PB0112B) issued on September 12, 2008 for Comanche Units 1 and 2 set a PM emission limitation of 0.03 lb/MMBtu, which is more

stringent than the limit of 0.1 lb/MMBtu that currently applies to these units. Although test results indicate that emissions below the 0.03 lb/MMBtu BART limit are certainly achievable, the 2003 performance test is just one 3-hour test and does not necessarily represent achievable emission rates over all operating conditions. Therefore, the Division considers that the PM limit set the BART permit is still appropriate. Using the allowable post-control PM BART limit of 0.03 lb/MMBtu BART limit, the control efficiency of the baghouses are indicated in Table 8 above.

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for $PM/PM_{10}$ is not needed for Comanche Units 1 and 2.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies

In various submittals with respect to installing additional $NO_X$ controls on Comanche Units 1 and 2, PSCo looked at two options:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

As part of this BART evaluation, the Division identified and examined the following additional control options for these units:

- Powerspan Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Rotating Opposed Fired Air (ROFA), ROFA with SNCR
- Low $NO_X$ Burners (LNB) with Separated Overfire Air (SOFA)
- Reburning
- Emission limit tightening

Since low $NO_X$ burners with over-fire air (LNB-OFA) were recently installed on Units 1 and 2 (November 2008 for Unit 1 and November 2007 for Unit 2), the Division considers that further upgrades to the LNB-OFA would provide little in the way of additional reductions and therefore upgrades to the existing LNB-OFA were not considered.

Step 2: Eliminate Technically Infeasible Options

*Selective non-catalytic reduction (SNCR):* The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between $NO_X$ in the flue gas and either injected ammonia or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the $NO_X$ reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of $NO_X$. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of $NO_X$ with SNCR is the temperature of the flue gas at the point where the reagent is injected. The necessary temperature range is 1,600 - 2,100°F. SNCR can typically achieve $NO_X$ reductions on the order of 40-70%.

PSCo has indicated that SNCR is feasible for Unit 1. According to their April 6, 2009 submittal, PSCo conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. The testing was done following the installation of LNB-OFA to determine if additional reductions could be achieved. Testing was conducted primarily at full load over a seven-day period using a single-level urea based-SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 ºF, which exceeds the optimal temperature for the technology. During the test periods, $NO_X$ reductions were less than 10%, and in some cases during testing, an actual increase in $NO_X$ emissions was seen. Therefore, PSCo considers that SNCR is not feasible on Unit 2 and the Division concurs.

*Selective Catalytic Reduction (SCR):* SCR systems are the most widely used post-combustion $NO_X$ control technology on pulverized coal-fired boilers. The SCR process is an add-on control which uses a catalyst bed and ammonia injection for removal of $NO_X$ emissions. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the $NO_X$ decomposition reaction. SCR systems can achieve $NO_X$ reductions in the range of 60 – 90%. SCR is technically feasible for Comanche Units 1 and 2.

*Powerspan Electro-Catalytic Oxidation (ECO)®:* The Powerspan electrostatic oxidation process (ECO)® is an integrated air pollution control process that achieve reductions in multiple pollutants from coal-fired power plants, included $NO_X$, $SO_2$, mercury and fine particulate matter (particulate matter less than 2.5 microns). The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse and consists of an ECO reactor (to oxidize pollutants), absorber vessel (saturates and cools the flue gas, removes $SO_2$, $NO_2$ and oxidized mercury) and a wet electrostatic precipitator (removes acid aerosols, air toxics and fine particulate matter). To date the ECO® system has been used on a slipstream (50 MW) from a 156 MW boiler equipped with an

electrostatic precipitator and low $NO_X$ burners[6]. While the technology may be considered commercially available, it has only been demonstrated on the portion of the exhaust of a smaller boiler. Therefore, the Division considers that this technology is not feasible.

*Rich Reagent Injection (RRI):* Rich reagent injection is the process of adding $NO_X$ reducing agents in a staged lower furnace to reduce the formation of $NO_X$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_X$ reductions. The combustion process is then completed with the use of overfire air. RRI is similar to SNCR but the reagent at the lower furnace at significantly higher temperatures (2400 – 3100ºF).[7] The RRI process was originally developed for coal-fired cyclone boilers and the Division is not aware that RRI has been utilized on other types of coal-fired boilers. Therefore, the Division considers that RRI is technically infeasible for Comanche Units 1 and 2.

*Rotating Opposed Fire Air (ROFA) and ROFA with SNCR:* With ROFA air in injected into the furnace first which breaks up the fireball and creates a swirling air flow to increase combustion. The swirling air results in better mixing of the fuel and air and distributes the temperature more evenly throughout the furnace, which improves combustion and reduces $NO_X$ emissions. Typical $NO_X$ reductions from ROFA alone range from 45 – 60 percent.[8] As indicated in Table 3, the estimated $NO_X$ reductions for Units 1 and 2 with LNB-OFA are over 55% percent. Since ROFA is not expected to provide more $NO_X$ reductions than the current controls on Units 1 and 2, further review of ROFA is not warranted.

That same ROFA system can be used to inject urea or ammonia into the furnace. However, since the $NO_X$ reduction efficiency for the Comanche Unit 1 and 2 LNB-OFA systems are comparable to ROFA, combining ROFA and SNCR is not likely to result in $NO_X$ reductions significantly above the level achieved by the Unit 1 existing LNB-OFA in conjunction with SNCR (note that SNCR is not feasible on Unit 2). Therefore, ROFA-SNCR will not be considered further.

*Low $NO_X$ Burners (LNB) with Separated Over Fire Air (SOFA):* Over-fire air (OFA) is a combustion control technology where a portion of the total combustion air is diverted from the burners and injected later in the combustion process, typically above the combustion zone. There are specific OFA configurations that are typically associated with tangentially-fired boilers, close-coupled to the burner, separated from the burner and combination. The high end of the $NO_X$ reduction ranges for the various OFA configurations for tangentially fired boilers are lower than the range for LNB-OFA on wall-fired units.[9] Since alternate OFA configurations will not result in significant $NO_X$ reductions beyond LNB-OFA, they will not be considered further.

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[6] http://www.powerspan.com/FirstEnergy_ECO.aspx
[7] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[8] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html
[9] Srivastava et. al, September 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association, volume 55, pg 1370.

*Reburning:* In reburning, a portion of the total heat input (up to 25%) is provided by injecting a secondary (reburning) fuel above the main combustion zone. Combustion of the reburning fuel results in hydrocarbon fragments, which react with a portion of incoming $NO_X$ which form nitrogen containing compounds which are ultimately reduced to $N_2$. The fuel used for reburning need not be the primary fuel. Natural gas has frequently been used as reburning fuel, as there are more issues to consider with coal as the reburn fuel (e.g. particle size). In general reburning can achieve greater than 50% $NO_X$ reduction, but many reburning demonstration projects are no longer operating.[10] Reburning can be used in conjunction with other $NO_X$ control technologies, such as LNB-OFA, SCR and SNCR. Given that the control efficiency with reburning alone is similar to the $NO_X$ reduction efficiency of Comanche Units 1and 2 with LNB-OFA (see Table 4), the Division considers that further evaluation of reburning is not warranted.

*Emission limit tightening*: The Division conducted technical analyses to determine whether the current $NO_x$ emission limit(s) could be more stringent based on actual emissions after installation of the low $NO_x$ burners with over-fire air (Unit 1 – December 2008 – Oct. 2010 and Unit 2 - December 2007 – October 2010). This option is technically feasible for both units.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals[11], determined that 30-day $NO_x$ rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. To be conservative, the Division projected an annual average emission rate at 15% for Comanche to determine control efficiencies and annual reductions.

The Division considered that two additional $NO_X$ reduction options warranted further consideration. Although some of the identified control technologies were not considered technically infeasible, they offered similar $NO_X$ reduction levels that are already achieved with the LNB-OFA installed on Comanche Units 1 and 2. The two additional $NO_X$ reduction technologies warranting further review are SCR and SNCR (Unit 1 only). \

*SNCR:* In their April 20, 2010 submittal, PSCo indicated that a $NO_X$ emission rate of 0.10 lb/MMBtu was achievable on Unit 1. The Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 29.5%. This control effectiveness estimate is roughly equivalent to EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers.

*SCR:* In their April 20, 2010 submittal, PSCo indicated that a $NO_X$ emission rate of 0.07 lb/MMBtu was achievable on both Units 1 and 2. Again, the Division calculated the control effectiveness based on the difference between the baseline (2009) and expected

[10] Srivastava et. al, pp 1371-1372.
[11] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

emission rate. This calculated control effectiveness for Comanche Unit 1 is 51% and for Comanche Unit 2 is 63%. These control efficiencies are lower than EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[12,13] However, the resultant emission rate of 0.07 lb/MMBtu is consistent with the rates cited in the AWMA study. PSCo and the Division recognize and concur that the lower initial emission rates of 0.124 and 0.165 lb/MMBtu for Units 1 and 2 respectively result in reduced SCR control efficiencies.

*Emission limit tightening*: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from current $NO_x$ emissions. The Division found that the maximum 30-day rolling emission rate for Unit 1 from December 2008 – October 2010 was about 0.15 lb/MMBtu and the average 30-day rolling rate was around 0.13 lb/MMBtu. For Unit 2, from December 2007 to October 2010, the maximum 30-day rolling emission rate was about 0.17 lb/MMBtu and the average 30-day rolling rate was around 0.17 lb/MMBtu. As explained above, the Division projects 30-day rolling $NO_x$ emission rates to be approximately 15% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 15% buffer to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy.

The Division also found that for 2009, the annual average emission rate for both units was approximately 0.15 lb/MMBtu, and a review of January – October 2010 found that annual average emission rate thus far is about 0.16 lb/MMBtu. The existing annual limit of 0.15 lb/MMBtu for both units is an appropriate $NO_x$ emission limit at this time. Therefore, appropriate $NO_x$ emission limits assuming existing low $NO_x$ burner with over-fire air technology for Units 1 and 2 are 0.20 lb/MMBtu on a 30-day rolling average for each unit and 0.15 lb/MMBtu annual average for both units. A re-evaluation of these emission limits will occur for the next regional haze planning period.
Table 9 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 9: Comanche Units 1 and 2 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| SNCR | 20 – 50% | Y |
| SCR | 50 – 90% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Low $NO_x$ Burners (LNB) | 10-30% | Y – installed |
| LNB + OFA | 25-45% | Y – installed |

[12] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[13] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

| | | |
|---|---|---|
| Air Staging – overfire air (OFA) | 5-40% | Y – installed |
| Rotating overfire air (ROFA) | 45 – 65% | N |
| Coal reburn+SNCR | n/a | N |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*SNCR and SCR:* In their January 19, 2010 submittal, PSCo provided cost information associated with SNCR for Unit 1 and SCR for both Units 1 and 2. PSCo used EPA's Coal Utility Environmental Costs (CUECost) workbook model to estimate capital and ongoing operating and maintenance costs. The costs were then levelized at 2016/2017 dollars based on a 20-yr life to determine annual costs. The levelized costs were reported in 2016/2017 dollars on the assumption that SNCR would be installed by 2015 and SCR would be installed by 2016, with an additional year to optimize operation of the new control equipment. PSCo submitted the inputs and outputs from CUECost to the Division in a March 1, 2010 e-mail to the Division. The levelized cost methodology and results were provided in Xcel internal memos dated February, 24, 2010 (submitted to the Division via e-mail on March 1, 2010) and April 16, 2010 (submitted via e-mail to the Division on April 21, 2010). According to PSCo's April 20, 2010 submittal, the cost per ton for SNCR for Unit 1 was estimated to be $ 4,342/ton and the cost per ton for SCR was estimated to be $15,173/ton for Unit 1 and $9,558/ton for Unit 2.

Although the Division does not dispute the levelized annual costs for SNCR and SCR, the baseline emission rates used to determine the cost per ton for the incremental reduction are not appropriate. For Unit 1, PSCo presumed baseline emission rates of 0.12 lb/MMBtu for SNCR and 0.13 lb/MMBtu for SCR and for Unit 2 PSCo presumed a baseline emission rate of 0.18 lb/MMBtu. The Division has set a baseline period of 2009. The baseline emission rates are shown in Table 1.

*SNCR:* A typical breakdown of annualized costs for SNCR on industrial boilerswill be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[14] The PSCo-estimated SNCR costs for operating expenses is about 69% for Comanche Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[15]

[14] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[15] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The Division-calculated cost effectiveness for SNCR on Unit 1 is $3,644 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 1) achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[16,17] It should be noted that PSCo is estimating resultant emission rates much lower than 0.30 lb/MMBtu for this boiler. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[18] PSCo's estimates are above this range. However, the Division concludes that PSCo's cost estimates for SNCR are reasonable due to the low input $NO_x$ emission rate and degree of retrofit difficulty.

*SCR:* Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[19,20] In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 15.3% is just slightly higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.[21] PSCo's cost estimates are above the NESCAUM study ranges due to the lower control efficiencies explained earlier. The Division concludes that PSCo's cost estimates for SCR are reasonable due to low emission reductions and retrofit difficulties.

Table 10, Table 11, Table 12, and Table 13 depict controlled $NO_x$ emissions and control cost comparisons. Refer to "Comanche APCD Technical Analysis" for more details.

**Table 10: Comanche Unit 1 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,511 | 0.124 | |

[16] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[17] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[18] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[19] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[20] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[21] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

| | | | | |
|---|---|---|---|---|
| SNCR* | 29.5 | 1,065 | 0.087 | 0.100 |
| SCR** | 51 | 740 | 0.061 | 0.070 |

*Determined based on difference between baseline (2009) and PSCo's expected emission rates
**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

**Table 11: Comanche Unit 2 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 2,349 | 0.165 | |
| SCR** | 63 | 869 | 0.061 | 0.070 |

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

**Table 12: Comanche Unit 1 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| SNCR | 445.6 | $1,624,100 | $3,644 | --- |
| SCR | 770.4 | $12,265,014 | $15,920 | $32,762 |

**Table 13: Comanche Unit 2$NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| SCR | 1,480 | $14,650,885 | $9,900 | --- |

Energy and Non-Air Quality Impacts

*SNCR and SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam

in some cases. 100 – 300 kW is enough energy to power about 10 homes for a year. These energy requirements are minimal and were confirmed by PSCo in the January 19, 2010 submittal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. PSCo noted that the retrofit installation of an SCR typically requires the installation of new, larger induced draft fans to over-come the additional pressure drop created by the SCR catalyst. In addition, although PSCo acknowledged that the energy requirements for SCR are more significant than SNCR they did not quantify these impacts since the increase in house power usage are included in the ongoing operating costs for each technology in the CUECost model.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

PSCo did identify the change in operating mode for the coal fired boilers as more wind energy is brought onto the PSCo system as a non-air quality impact that would affect any $NO_X$ control technology. PSCo noted that typically coal-fired boilers are operated as base-loaded units and as such they typically run at full load 24-hours a day, with only minor load reductions at night when demand is lower or during off-peak periods in the spring and fall. However, with more wind resources replacing other conventional power sources, the load may be dropped further since demand for power is less. Therefore, the load on coal-fired units may be further reduced, particularly during peak wind generating periods. PSCo considers that operating these units at lower loads may affect the $NO_X$ control technologies and result in lower $NO_X$ reductions than those that would be seen at high loads.

*Emission Limit Tightening*: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

In their January 19, 2010 submittal PSCo indicated that the remaining useful life of Comanche Units 1 and 2 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $NO_x$ BART control technology on a given unit, emission rates for the other pollutants ($SO_2$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1<br>2 | 0.40<br>0.53 | Great Sand Dunes National | 60 | --- | --- | 27 | --- | --- |
| NOx @ | 1 | 0.20 | | 60 | 57 | 3 | 27 | 24 | 3 |

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 0.20 lb/MMBtu | | | Park | | | | | | |
| NOx @ 0.20 lb/MMBtu | 2 | 0.20 | | 60 | 51 | 9 | 27 | 21 | 6 |
| SNCR @ 0.10 lb/MMBtu | 1 | 0.10 | | 60 | 51 | 9 | 27 | 22 | 5 |
| SNCR not feasible | 2 | n/a | | 60 | n/a | n/a | 27 | n/a | n/a |
| SCR @ 0.07 lb/MMBtu | 1 | 0.07 | | 60 | 51 | 9 | 27 | 21 | 6 |
| SCR @ 0.07 lb/MMBtu | 2 | 0.07 | | 60 | 47 | 13 | 27 | 18 | 9 |
| Combo | 1<br>2 | 0.07 | | 60 | 4 | 56 | 27 | 1 | 26 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

**Table 15: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Impact Improvement from new LNB (2009) | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hour | 1<br>2 | 0.40<br>0.53 | 2.05 | --- | --- | --- | --- |
| New LNB (2009) | 1 | 0.20 | 1.90 | 0.16 | n/a | 8% | n/a |
| | 2 | 0.20 | 1.75 | 0.31 | n/a | 15% | n/a |
| SNCR | 1 | 0.10 | 1.79 | 0.26 | 0.11 | 13% | $6,175,284 |
| SNCR not feasible | 2 | n/a | | | | | |
| SCR | 1 | 0.07 | 1.76 | 0.30 | 0.14 | 14% | $41,576,317 |
| | 2 | 0.07 | 1.58 | 0.47 | 0.17 | 23% | $31,172,095 |
| Combo | 1<br>2 | 0.07 | 0.36 | 1.69 | n/a | 82% | n/a |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein , the state has determined that $NO_x$ BART is following existing $NO_x$ emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)

| | |
|---|---|
| | 0.15 lb/MMBtu (combined annual average for units 1 & 2) |
| Comanche Unit 2: | 0.20 lb/MMBtu (30-day rolling average) |
| | 0.15 lb/MMBtu (combined annual average for units 1 & 2) |

The state assumes that the BART emission limits can be achieved through the operation of existing low $NO_x$ burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined based on the high cost/effectiveness ratios to not be reasonable coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Tri-State Generation & Transmission Association, Inc. |
| Source Type: | Electric Utility Steam Generating Unit |
| SCC (EGU): | 10100222 |
| Boiler Type: | Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2) |

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide ($SO_2$) emissions. The boilers are equipped with ultra-low nitrogen oxide ($NO_x$) dual register burners with overfired air for minimization of $NO_x$ emissions. The FGD and ultra low $NO_x$ burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of $SO_2$ and low-$NO_x$ burners with overfired air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for $NO_x$ limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Table 1 lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

**Table 1: Craig Boilers Technical Information**

| | Unit 1 | Unit 2 |
|---|---|---|
| Placed in Service | 1980 | 1979 |
| Gross Boiler Rating, MMBtu/Hr for coal | 4,417 | 4,417 |
| Electrical Power Rating, Net Megawatts | 428 | 428 |
| Description | Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization. | Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization. |
| Air Pollution Control Equipment | $PM/PM_{10}$ – Pulse Jet Fabric Filter Baghouse<br>$NO_x$ – Ultra-low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Wet Limestone FGD<br>All updated control equipment commenced full operations in 2004. | $PM/PM_{10}$ – Pulse Jet Fabric Filter Baghouse<br>$NO_x$ – Ultra-low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Wet Limestone FGD<br>All updated control equipment commenced full operations in 2004. |
| Emissions Reduction (%)* | $NO_x$ – 23.8% /53.9%<br>$SO_2$ – 77.6%/93.8%<br>PM – 99.6%<br>$PM_{10}$ – 99.4% | $NO_x$ – 29.5%/54.7%<br>$SO_2$ – 79.5%/93.8%<br>PM – 99.9%<br>$PM_{10}$ – 99.5% |

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first $NO_x$ number compares the additional reduction achieved by the ultra-low $NO_x$ burners vs. the original low-$NO_x$ burners and the second $NO_x$ number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For $PM/PM_{10}$., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and in existence in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "Tri-State BART Submittals".

## II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses.

Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

**Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions**

| Pollutant | Unit 1 | | Unit 2 | |
|---|---|---|---|---|
| | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) |
| $NO_x$ | 5,190 | 0.278 | 5,372 | 0.271 |
| $SO_2$ | 970 | 0.052 | 982 | 0.050 |
| $PM_{10}$ | 80 | 0.006*** | 40 | 0.005*** |

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions.
***The $PM_{10}$ emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

## III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of $NO_x$-forming characteristics, Craig 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing $NO_x$ formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

**Table 3: Craig Station Coal Specifications (2008)**

| Coal Mine/Region | ColoWyo | Trapper | Twentymile |
|---|---|---|---|
| Coal Rank Classification | Sub-bituminous, Class A | Sub-bituminous, Class A | Bituminous |
| $H_2O$ (Moisture %) | 17.42 | 16.7 | 9.62 |
| Ash (%) | 5.71 | 6.5 | 11.93 |
| Sulfur (%) | 0.37 | 0.44 | 0.52 |
| Nitrogen (%) | 1.35 | ~1.5 | 1.57 |
| Heating Value (HHV Btu/lb) | 10,392 | 9,800 | 11,084 |

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

**Table 4: Uncontrolled emission factors for Craig BART-eligible sources[1]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Unit 1 | 12 | 16.9 | 73.9 | 17.0 |
| Unit 2 | 12 | 16.1 | 71.1 | 16.4 |

*$SO_2$ and $PM/PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

## IV. BART Evaluation of Units 1 and 2

### A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

*Wet FGD Upgrades* – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

**Table 5: Craig Units 1 & 2 $SO_2$ Operating Permit Limits**

| | $SO_2$ limits (lb/MMBtu) | | | Reduction (%) Required |
|---|---|---|---|---|
| | 3-hr rolling | 30-day rolling | 90-day rolling | 90-day rolling |
| Units 1 & 2 | 1.2 | 0.160 | 0.130 | 90 |

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division's request, Tri-State submitted a $SO_2$ upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State examined potential upgrades to the Craig wet FGD systems, with the following results:

-*Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-*Installation of liquid distribution rings:* Liquid distribution rings were not installed during the YEP; however, Tri-State determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of $SO_2$ by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve $SO_2$ removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:

1. DBA has not been tested at the very low inlet $SO_2$ concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on $SO_2$ removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased $SO_2$ removal.

-*Improve or upgrade scrubber auxiliary equipment:* YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased $SO_2$ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high $SO_2$ removal rates.

2. Forced oxidation within the $SO_2$ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.

3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.

5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.

6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased $SO_2$ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.

7. Instrumentation and controls were modified to support all of the new equipment.

-*Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the $SO_2$ emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

**Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)**

| Unit | Maximum 30-day rolling emission rate (lb/MMBtu) | Average 30-day rolling emission rate (lb/MMBtu) |
|---|---|---|
| Craig Unit 1 | 0.081 | 0.052 |
| Craig Unit 2 | 0.093 | 0.079 |

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results ($98^{th}$ percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants ($NO_x$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions at 0.10 lb/MMBtu (wet FGD).

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1 | 0.166 | Mt. Zirkel Wilderness | 207 | --- | --- | 123 | --- | --- |
| | 2 | 0.161 | | | | | | | |
| Wet FGD | 1 | 0.150 | | 207 | 206 | 1 | 123 | 123 | 0 |
| | 2 | 0.150 | | 207 | 207 | 0 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.120 | | 207 | 204 | 3 | 123 | 123 | 0 |
| | 2 | 0.120 | | 207 | 204 | 3 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.110* | | n/a | | | | | |
| | 2 | 0.110* | | n/a | | | | | |
| Wet FGD | 1 | 0.100 | | 207 | 203 | 4 | 123 | 123 | 0 |
| | 2 | 0.100 | | 207 | 203 | 4 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.070 | | 207 | 202 | 5 | 123 | 122 | 1 |
| | 2 | 0.070 | | 207 | 203 | 4 | 123 | 122 | 1 |
| Combo | 1 | 0.100 | | 207 | 57 | 150 | 123 | 12 | 111 |
| | 2 | 0.100 | | | | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

**Table 8: Visibility Results – $SO_2$ Control Options**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact)* | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) |
| Max 24-hour | 1 | 0.166 | 3.73 | --- | --- |
| | 2 | 0.161 | | | |
| Wet FGD | 1 | 0.150 | 3.72 | 0.01 | 0% |
| | 2 | 0.150 | 3.72 | 0.01 | 0% |
| Wet FGD | 1 | 0.120 | 3.70 | 0.02 | 1% |
| | 2 | 0.120 | 3.71 | 0.02 | 1% |
| Wet FGD | 1 | 0.110* | 3.70 | 0.03 | 1% |
| | 2 | 0.110* | 3.70 | 0.03 | 1% |
| Wet FGD | 1 | 0.100 | 3.69 | 0.03 | 1% |
| | 2 | 0.100 | 3.70 | 0.03 | 1% |
| Wet FGD | 1 | 0.070 | 3.68 | 0.05 | 1% |
| | 2 | 0.070 | 3.68 | 0.05 | 1% |
| Combo | 1 | 0.070 | 1.17 | 2.56 | 69% |
| | 2 | 0.070 | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An $SO_2$ limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

## B. Filterable Particulate Matter ($PM_{10}$)

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control $PM/PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

**Table 9: Craig Units 1 and 2 Stack Test Results (2004)**

| Pollutant | Unit 1 (lb/MMBtu) | Unit 2 (lb/MMBtu) |
|---|---|---|
| Filterable $PM_{10}$ | 0.006 | 0.005 |
| $PM_{10}$ Control efficiency | 99.23% | 99.35% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies
Tri-State identified five options for $NO_x$ control:
New/modified Low $NO_x$ Burners (LNBs) with Overfired Air (OFA) system (next generation)
Advanced OFA system or Rotating overfired Air (ROFA)
Neural network system combustion controls
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Craig Units 1 and 2 currently have ultra-low $NO_x$ burners with over-fire air (ULNBs+OFA) installed (2004) for $NO_x$ control purposes.

Step 2: Eliminate Technically Infeasible Options

*LNBs with OFA Upgrades:* Tri-State contracted with ACT to modify the existing Craig 1&2 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-$NO_x$ Babcock & Wilcox 4Z burners such as those in use at Craig Units 1 and 2. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed $NO_x$ reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Units 1 and 2.

*Advanced OFA system – rotating overfired air system (ROFA):* ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give Tri-State a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

*Neural network system combustion controls:* Tri-State received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. Tri-State states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential $NO_x$ reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

*SNCR:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

*SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

While a lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected, although Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfired air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

[5] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[6] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

*LNB/SOFA/LNB+SOFA:* Craig Units 1 and 2 are already equipped with ultra-low $NO_x$ burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% $NO_x$ reductions (based on actual emissions) on Units 1 and 2, respectively.

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

*LNBs with OFA Upgrades:* Tri-State noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% $NO_x$ reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

*Neural network system combustion controls:* Tri-State noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% $NO_x$ reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control.

[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

*SNCR:* Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous $NO_x$ reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and W.H. Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% $NO_x$ control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

*SCR:* Tri-State stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve $NO_x$ reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% $NO_x$ emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

[9] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.
[10] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

**Table 10: SCR Control Efficiency Comparison**

| Unit | Baseline (lb/MMBtu) | Control Efficiency (%) | | Resultant Emissions (lb/MMBtu) | |
|---|---|---|---|---|---|
| | | Tri-State Estimate | Division Estimate | Tri-State Estimate (annual average) | Division Estimate (annual average) |
| Craig Unit 1 | 0.278 | 71.4 | 74.9 | 0.080 | 0.070 |
| Craig Unit 2 | 0.271 | 70.5 | 74.0 | 0.080 | 0.070 |

Table 11 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners/Ultra-low $NO_x$ burners (LNB/ULNB) | 10-30% | Y – installed |
| LNB + OFA | 25-45% | Y – installed |
| Air Staging – overfired air (OFA) | 5-40% | Y – installed |
| Ultra-Low $NO_x$ Burner (ULNB) Upgrade/Refinements | 0 – 2% (Tri-State) | Y |
| Neural network system | 0 – 5% (Tri-State) | Y |
| SNCR | ~15% | Y |
| Rotating overfired air (ROFA) | 45 – 65% | N |
| SCR | 75 – 90% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Coal reburn+SNCR | n/a | N |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*Low $NO_x$ burner upgrades:* Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low $NO_x$ burners with overfired air. Ultra-low $NO_x$ burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.[11] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

*Neural network system:* Tri-State did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that Tri-State contacted.[12] It is unknown why Tri-State will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

*SNCR:* A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[13] The Tri-State-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[14]

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately $4,877 and $4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor. [15,16] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[17] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from Tri-State. The costs for these two items are higher than other Colorado facility estimates.

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[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.

[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[15] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

*SCR:* Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving $NO_x$ emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[18,19 20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 12: Craig Unit 1 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 5,190 | 0.278 | |
| Combustion control refinements | 2 | 5,087 | 0.273 | 0.31 |
| Neural network system | 5 | 4,931 | 0.264 | 0.30 |
| SNCR | 15 | 4,412 | 0.236 | 0.27 |
| SCR | 78.0 | 1,142 | 0.061 | 0.070 |

[18] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

**Table 13: Craig Unit 2 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 5,372 | 0.271 | |
| Combustion control refinements | 2 | 5,264 | 0.265 | 0.31 |
| Neural network system | 5 | | 0.257 | 0.30 |
| SNCR | 15 | 4,566 | 0.230 | 0.27 |
| SCR | 74 | 1,397 | 0.070 | 0.081 |

**Table 14: Craig Unit 1 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Combustion control refinements | 104 | $122,000 | $1,175 | $1,175 |
| Neural network system | 260 | $280,000 | $1,079 | $1,015 |
| SNCR | 779 | $3,797,000 | $4,877 | $6,776 |
| SCR | 4,048 | $25,036,709 | $6,184 | $6,394 |

**Table 15: Craig Unit 2 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Combustion control refinements | 107 | $122,000 | $1,136 | $1,136 |
| Neural network system | 269 | $280,000 | $1,043 | $980 |
| SNCR | 806 | $3,797,000 | $4,712 | $4,712 |
| SCR | 3,975 | $25,036,709 | $6,298 | $6,702 |

Energy and Non-Air Quality Impacts

*LNB Upgrades/Neural network system(s):* There are no known non-air quality impacts associated with upgrades on low-$NO_x$ burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/ SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results ($98^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels.

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1 | 0.352 | Mt. Zirkel Wilderness | 207 | --- | --- | 123 | --- | --- |
| | 2 | 0.345 | | | | | | | |
| SNCR | 1 | 0.236 | | 207 | 192 | 15 | 123 | 123 | 0 |
| | 2 | 0.230 | | 207 | 194 | 13 | 123 | 123 | 0 |
| SCR | 1 | 0.07 | | 207 | 165 | 42 | 123 | 123 | 0 |
| | 2 | 0.07 | | 207 | 166 | 41 | 123 | 123 | 0 |
| Combo | 1 | 0.07 | | 207 | 57 | 150 | 123 | 12 | 111 |
| | 2 | 0.07 | | | | | | | |

**Table 17: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hour | 1 | 0.352 | 3.73 | --- | --- | --- |
| | 2 | 0.345 | | | | |
| SNCR | 1 | 0.236 | 3.42 | 0.31 | 8% | $12,327,922 |
| | 2 | 0.230 | 3.42 | 0.31 | 8% | $12,327,922 |
| SCR | 1 | 0.07 | 2.72 | 1.01 | 27% | $24,887,384 |
| | 2 | 0.08 | 2.79 | 0.94 | 25% | $26,691,207 |
| Combo | 1 | 0.07 | 1.17 | 2.56 | 69% | $19,537,034 |
| | 2 | 0.07 | | | | |

Step 6: Select BART Control

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that they can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan. The criteria in Chapter 6 guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the notable visibility improvements, the reasonable dollars per ton control costs, and the support of Tri-State for installation of SCR at Units 1 and 2.

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's decision to approve Colorado's Regional Plan.

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination In Table 19 below, an assumed amortization period of eight years of operation[23] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[24]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

**Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
|---|---|---|---|
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $6,172,522 | $7,928 |
| SCR | 4,048 | $64,106,699 | $15,835 |

**Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
|---|---|---|---|
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $4,755,842 | $6,109 |
| SCR | 4,048 | $41,476,535 | $10,245 |

Based on this assessment, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life; or
Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

[23] Operation period begins calendar year 2018 (December 31, 2017).
[24] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until closing or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination.

Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Colorado Springs Utilities – Drake Plant**

## I. Source Description

Owner/Operator: Colorado Springs Utilities
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100202
Boiler Type: Three Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas (Units 5, 6, and 7)

The facility is located at 700 South Conejos Street in Colorado Springs. This facility consists of three (3) steam driven turbine/generator units (Units 5, 6, and 7) and the associated equipment needed for generating electricity. These units fire coal as the primary fuel and use natural gas for backup and startup. The facility also includes the various processes necessary to handle the coal and ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control of PM and $PM_{10}$ at appropriate point sources. In addition, the coal is treated with chemical additives to reduce fugitive emissions. Table 1 depicts technical information for each boiler at the Drake Plant.

**Table 1: Drake Boilers Technical Information**

| | Unit 5 | Unit 6 | Unit 7 |
|---|---|---|---|
| Placed in Service | October 28, 1962 | July 27, 1968 | June 14,1974 |
| Boiler Rating, MMBtu/Hr for coal | 548 | 861 | 1,336 |
| Electrical Power Rating, Gross Megawatts | 51 | 85 | 142 |
| Description | Riley Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 548 MMBtu/Hr w/ coal, 514 MMBtu/Hr w/ NG. | Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 861 MMBtu/Hr w/ coal 850 MMBtu/Hr w/ NG. | Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 1336 MMBtu/Hr w/Coal, 1310 MMBtu/Hr w/ NG. |
| Air Pollution Control Equipment | Reverse-Air Fabric Filter Baghouse- installed in May 1998 | Reverse-Air Fabric Filter Baghouse – installed in September 1978 | Reverse-Air Fabric Filter Baghouse– installed in November 1993 |
| Inherent Special Features | Low $NO_x$ burners – placed in service in May 1998 | Low $NO_x$ burners – placed in service in March 1998 | Low $NO_x$ burners – placed in service in October 1999 |
| Monitoring Equipment | COM<br>CEMs for $SO_2$ , NOx, | COM<br>CEMs for $SO_2$ , NOx, | COM<br>CEMs for $SO_2$ , NOx, |

| | | | |
|---|---|---|---|
| | $CO_2$, and stack gas flow rate | $CO_2$, and stack gas flow rate | $CO_2$, and stack gas flow rate |
| Emissions Reduction (%)* | $NO_x$ – 54.7%<br>$SO_2$ – None<br>PM – 99.7%<br>$PM_{10}$ – 98.6% | $NO_x$ – 52.8%<br>$SO_2$ – None<br>PM – 99.6%<br>$PM_{10}$ – 98.2% | $NO_x$ – 57.7%<br>$SO_2$ – None<br>PM – 99.8%<br>$PM_{10}$ – 99.1% |

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for $PM/PM_{10}$. For $NO_x$ estimates, CAMD data was used to calculate reduction. See "Drake APCD Technical Analysis" for further details. Not based on actual testing.

Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a $98^{th}$ percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010. These documents are all provided as "CSU Drake BART Submittals".

Regulations that apply to these boilers are as follows:

- State Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu.
- State Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits $NO_X$ emissions to 0.46 lb/MMBtu of heat input on an annual average basis.
- No other annual emission limitations or State Regulations since units are Grandfathered[1].

## II. Emissions for Units 5, 6, & 7

CSU estimated that a realistic depiction of anticipated annual emissions for Boilers 5, 6, and 7, or "Baseline Emissions", to be conservative, was the average of two previous years (2004, 2005) of emissions data in the August 1, 2006 analysis. Several years have

[1] Colorado Department of Public Health and Environment Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emission Notice Requirements 5 CCR 1001-5 Part G.IV states: "A source existing before the adoption of the first Colorado Air Quality Control Act and the date of its implementing regulations of February 1, 1972, is not required to obtain a permit. This revision is intended to clarify the date prior to which existing sources are considered "grandfathered" and exempt from permit requirements."

passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database as applicable. These emissions are summarized in Table 2.

**Table 2: CSU Boilers 5, 6 and 7 Baseline Emissions**

| Pollutant | Boiler 5 | | Boiler 6 | | Boiler 7 | |
|---|---|---|---|---|---|---|
| | Annual Emissions* (tpy) | Annual Emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Annual Emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Annual Emissions** (lb/MMBtu) |
| $NO_x$ | 768 | 0.38 | 1,413 | 0.42 | 2,081 | 0.39 |
| $SO_2$ | 1,269 | 0.63 | 2,785 | 0.82 | 4,429 | 0.83 |
| $PM_{10}$ | 27 | 0.01*** | 58 | 0.02*** | 55 | 0.01*** |

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions.
***The $PM_{10}$ emission rate is determined from the Title V permit compliance stack test. These values are as follows: Drake #5 – 0.0132 lb/MMBtu; Drake #6 – 0.0186 lb/MMBtu; Drake #7 – 0.0111 lb/MMBtu.

## III. Units Evaluated for Control

As documented by CSU, these boilers fire a variety of coal types, including coal from the southern Powder River Basin (PRB, located in Wyoming), ColoWyo coal (from northwestern Colorado), 20-Mile Foidel Creek coal (northwestern Colorado), and West Elk coal (western Colorado). The specifications for these coals are listed below in Table 3 (averaged from 2006 – 2008). Table 4 lists the 2006 – 2008 averaged APEN-reported coal characteristics for each boiler. Table 4 is not based on percent of various coals fired, but instead based on the Division's Air Pollutant Emission Notice (APEN) database. Sources submit annual emissions data using APENs. Due to equipment limitations, these boilers cannot achieve full load on PRB-sourced coal and instead fire a blend of the above listed coals. The ratio of PRB was discussed in the initial BART analysis submitted by CSU in an effort to demonstrate that firing sub-bituminous coal may have a minimal effect (if any) on a boiler's NOx emissions. In fact the data suggested at that time that 100% sub-bituminous coal had no effect on NOx emissions for some of the boilers. CSU notes that this effect may be boiler specific. The difference in sulfur content and resultant $SO_2$ emissions was not discussed in the initial BART analysis. Colorado's BART guidance (Regulation No. 3, Part F, Section IV.B.1.f) states that sources may include an evaluation of representative characteristics of coals from sources they reasonably expect to use, so that these characteristics may be considered in a particular BART limit.

**Table 3: Drake Plant Coal Specifications (2004 – 2005)**

| Coal Mine/Region | Southern PRB | Colowyo | 20-Mile Foidel Creek | West Elk |
|---|---|---|---|---|
| Coal Rank Classification | Sub-bituminous | Sub-bituminous, Class A | Bituminous | Bituminous |

| As Received Analysis | | | | |
|---|---|---|---|---|
| $H_2O$ (Moisture %) | 27.11 | 17.42 | 9.62 | 7.55 |
| Ash (%) | 4.64 | 5.71 | 11.93 | 8.71 |
| Sulfur (%) | 0.21 | 0.37 | 0.52 | 0.45 |
| Nitrogen (%) | 0.69 | 1.35 | 1.57 | 1.30 |
| Heating Value (HHV Btu/lb) | 8,805 | 10,392 | 11,084 | 12,266 |

**Table 4: Coal Specifications (2006 – 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| Boiler #5 | 9,798 | 0.36 | 8.14 |
| Boiler #6 | 10,749 | 0.47 | 10.38 |
| Boiler #7 | 11,117 | 0.50 | 11.14 |

Table 1 lists the units at Colorado Springs Utilities Drake Plant that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 5. The factors are based on firing bituminous coal for conservative estimates.

**Table 5: Uncontrolled emission factors for CSU Drake BART-eligible sources[2]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Boiler #5 | 22 | 13.6 | 81.5 | 18.7 |
| Boiler #6 | 22 | 18.0 | 103.8 | 23.9 |
| Boiler #7 | 22 | 18.8 | 111.4 | 25.6 |

*$SO_2$ and PM/$PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 4.

## A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

CSU identified one control option for Units 6 and 7:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
CSU identified two control options for Unit 5:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
Dry sorbent injection – Trona (DSI)

The Division also identified and examined additional control options for these units:
Lime/limestone-based wet FGD – all units
Emission limit tightening – Unit 5 (no control)

Step 2: Eliminate Technically Infeasible Options

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber that uses slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that results in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

*Dry FGD:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling $SO_2$ Emissions: A Review of Technologies[4] evaluates various $SO_2$ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks. The plant is bounded to the north by West Cimarron Street, to the west by federal Interstate Highway 25 and Fountain Creek, to the east by Conejos Street, and the south by Fountain Creek (as the Interstate and the Creek curve to the southeast). Train tracks (the Drake rail spur) also bound the facility to the north, south, and west. Along the east side of the plan (immediately east of Conejos Street) is the main railroad line. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the Drake Plant, due to locations as well as pollution control retrofits for particulate matter. As figure 2 indicates, the square footage available to accommodate a FGD for Unit 5 is 3,025 $ft^2$ and Units 6 & 7 is 8,346 $ft^2$ (or about 4,000 $ft^2$ per unit). The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. Demolition and site reconfiguration would be required for FGD systems on these units and has been included in the cost analysis provided by Drake. CSU determined that it is technically feasible to install a dry FGD on Unit 5, Unit 6 and Unit 7.

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.




**Figure 1: Drake Plant Physical Boundaries**

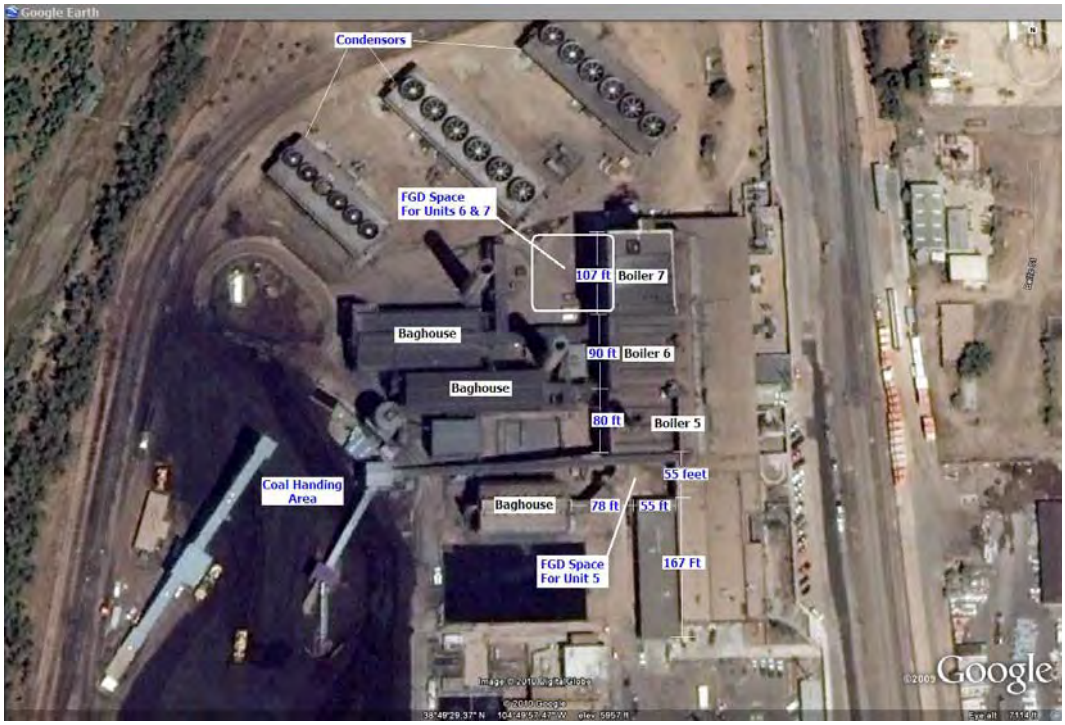


**Figure 2: Drake Plant Detailed View**

The Division conducted site visits and determined:

- Unit 5
    - CSU determined dry FGD controls are technically feasible although available physical space was severely constrained and some demolition and site reconfiguration would be required; the Division conducted a site visit and determined that dry FGD controls were not appropriate considering the space constraints, shown in Figure 1 and Figure 2. Therefore control effectiveness and impacts for dry FGD are not evaluated in this analysis.
    - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Unit 5.
- Units 6 and 7
    - Dry FGD controls are technically feasible for Units 6 and 7.
    - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Units 6 and 7.

It is worth noting that CSU-Drake is currently testing a new, innovative non-traditional wet scrubber control system that appears to be as effective, if not more effective, at controlling $SO_2$ emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system, called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4. Regarding the applicability of the NeuStream process to Drake Unit 5, the Division notes that this technology is not commercially available at this time. CSU has not determined if this technology is feasible for this smaller unit. However, the Division will re-assess this technology in the next Regional Haze planning period.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber. This process will be required to meet the emission limits established for the LSD technology established in this BART determination. Regardless of the technology utilized, Drake has to meet the LSD-based BART limits within 5 years of EPA approval of the BART

SIP. CSU will test the NeuStream system until December 2011, and at that time, determine the control technology that will be used to comply with the specified $SO_2$ BART limits for Units 6 and 7.

***DSI:*** Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the $SO_2$ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the Unit 5 airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the $NO_x$ present in the flue gas from NO which is colorless to $NO_2$ which has a reddish-brown color. This conversion of NO to $NO_2$ can create a brown plume from the stack which could create opacity compliance issues. Due to variability of boiler configurations, coal composition, $NO_x$ to $SO_2$ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum $SO_2$ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum $SO_2$ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% $SO_2$ removal. In practical application, a higher $SO_2$ removal rate may be possible, while it is also possible that a lower $SO_2$ removal rate may be necessary to limit the brown plume formation. This determination would require actual $SO_2$ removal real-time testing. Therefore, DSI is technically feasible for Drake Plant Unit 5. The Division assumes that this same technology is also then technically feasible for Unit 6 and Unit 7.

*Emission limit tightening (unit 5 only)*: The Division conducted technical analyses to determine whether the current $SO_2$ emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for all units. However, the Division only examined this option for Unit 5 since when this option was examined; preliminary $SO_2$ determinations had already been established for all units. Unit 5 was the only unit where the emission limit could potentially be achieved with the assumption of no control.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day $SO_2$ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Units 5, 6, and 7 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT $SO_2$ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

*Dry FGD (LSD):* Controlling $SO_2$ Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Drake Power Plant, typically <0.5% as detailed in Table 3, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Additionally, achievement of a 90% removal rate on a long-term basis would require levels of equipment redundancy that may not be feasible to locate at a congested site such as the Drake Power Plant.
*DSI:* Based on literature review, CSU estimated the maximum $SO_2$ removal rate that can be achieved to be 60% $SO_2$ removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

*Emission limit tightening*: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) $SO_2$ emissions. The Division found that the maximum 30-day rolling emission rate for Unit 5 was 0.83 lb/MMBtu. As explained above, the Division projects 30-day rolling $SO_2$ emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer to be applied in this case, especially due to the fact that the Drake facility has limited coal storage capacity and blends four different types of coals. Therefore, an appropriate $SO_2$ emission limit assuming no control technology for Unit 5 is 0.9 lb/MMBtu on a 30-day rolling average.

Table 6 summarizes each available technology and technical feasibility for $SO_2$ control.

[5] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

**Table 6: Drake Units 5, 6, and 7 $SO_2$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Wet FGD | 95% | Y |
| Dry FGD (LSD) | 81 – 90% | N – Unit 5<br>Y – Units 6 & 7 |
| DSI | 60% (CSU) | Y |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*Wet FGD*: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

*LSD/DSI:* CSU submitted cost estimates for LSD systems on Units 5, 6 and 7 in the original BART submittal on August 1, 2006 and updated refined cost estimates on March 29, 2007. CSU provided cost estimates for the DSI system evaluated on Unit 5 on May 10, 2010.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[6] shown in Table 7.

**Table 7: CSU-Drake $SO_2$ LSD Control Cost Comparison**

| Unit Capacity (MW) | EPA's Calculated Cost Effectiveness for MW Group ($/ton $SO_2$ Removed) | CSU Refined Cost Estimate ($/ton $SO_2$ Removed (Control System)) | Cost Differential |
|---|---|---|---|
| Unit 6 – | $2,399 | $2,579 - $2,981 | + 8% – 24% |

[6] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART $SO_2$ Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

| | | | |
|---|---|---|---|
| 85 MW | | | |
| Unit 7 – 142 MW | $1,796 | $2,140 - $2,694 | + 19% - 50% |

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Units 6 and 7 using various cost updates from the 2006 timeframe. Drake has reflected the costs of retrofitting a facility that is already congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. Therefore, the Division considers CSU's updated cost information for the LSD controls on these units to be reasonable estimations for the cost of control.

The Division considers this cost to be within a reasonable cost range that is comparable to other Colorado facility submittals.[7] Therefore, the Division did not adjust CSU's cost estimates. CSU only submitted DSI cost information for Unit 5. The Division scaled this cost information for Units 6 and 7 in Table 9, Table 10, and Table 11. Please see "Drake APCD Technical Analysis" for more details.

For dry FGD, CSU estimated a removal rate of 83.3% based on a worst-case coal sulfur concentration of 0.9 lb/MMBtu, baseline years 2004 and 2005, and a resulting emission rate at the BART presumptive limits of 0.15 lb/MMBtu. The Division adjusted this removal rate using the baseline $SO_2$ emissions from Table 2 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 76 – 90%that meets or exceeds BART presumptive limits for Units 6 and 7, and exceeds the limits for Unit 5. This range allows the Division to determine the most reasonable BART limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Division APCD Technical Analysis" for more details.

*Emission limit tightening:* There are no costs associated with this option for unit 5. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 8 illustrates resultant $SO_2$ emissions for each technically feasible control option. Table 9, Table 10, and Table 11 show the $SO_2$ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 2. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average $SO_2$ emission rate is approximately 5% higher than the annual average emission rate.

[7] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

**Table 8: Units 5, 6, and 7 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Unit 5 | | | Unit 6 | | | Unit 7 | | |
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day rolling Average (lb/MMBtu) | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day rolling Average (lb/MMBtu) | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day rolling Average (lb/MMBtu) |
| Baseline | --- | 1,269 | 0.63 | | 2,785 | 0.82 | | 4,429 | 0.83 | |
| DSI | 60 | 508 | 0.25 | 0.26 | 1,114 | 0.33 | 0.34 | 1,771 | 0.33 | 0.35 |
| Dry FGD (LSD) | 82 | | | | 501 | 0.15 | 0.15 | 797 | 0.15 | 0.16 |
| Dry FGD (LSD) | 85 | | | | 418 | 0.12 | 0.13 | 664 | 0.12 | 0.13 |
| Dry FGD (LSD) | 90 | | | | 279 | 0.08 | 0.09 | 433 | 0.08 | 0.09 |

**Table 9: Drake Unit 5 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| DSI | 762 | $1,340,663 | $1,760 | $1,760 |

**Table 10: Drake Unit 6 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| DSI | 1,671 | $2,234,438 | $1,337 | $1,337 |
| Dry FGD (LSD) @ 82% control | 2,284 | $6,186,854 | $2,709 | $6,540 |
| Dry FGD (LSD) @ 85% control | 2,368 | $6,647,835 | $2,808 | $5,517 |
| Dry FGD (LSD) @ 90% control | 2,507 | $7,452,788 | $2,973 | $5,780 |

**Table 11: Drake Unit 7 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| DSI | 2,657 | $3,732,826 | $1,405 | $1,405 |
| Dry FGD (LSD) @ 82% control | 3,632 | $8,216,863 | $2,263 | $4,602 |
| Dry FGD (LSD) @ 85% control | 3,764 | $8,829,321 | $2,345 | $4,610 |
| Dry FGD (LSD) @ 90% control | 3,986 | $9,898,382 | $2,483 | $4,828 |

Energy and Non-Air Quality Impacts

*Traditional Wet FGD:* Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[8]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART $SO_2$ control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of $SO_2$ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in $SO_2$ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

*Semi-dry FGD (LSD):* CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber.

[8] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

There will be a greater volume of material being landfilled. A LSD scrubber consumes a significant amount of water, as detailed in Table 12.

**Table 12: LSD Water Requirements**

| Unit | Water required for LSD (gpm) | Water required for LSD (Mg/year) |
|---|---|---|
| 6 | 68 | 35.7 |
| 7 | 100 | 53.0 |

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in **Error! Reference source not found.**. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of $CO_2$ when measured on a per MW-h basis.

**Table 13: LSD Energy Replacement Costs**

| Unit | Replacement capacity cost ($/kW-yr) | Differential energy cost ($/MW-h) |
|---|---|---|
| 6/7 | 44 | 35 |

This information, including detailed capital and annual cost data, are provided as "CSU Drake BART Submittals". CSU originally generated costs using EPRI's FGD Cost model.[9] This model uses specific unit data to calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. The refined cost estimates from March 2007 were further extrapolated to account for retrofit difficulties, annual inflation, and also hyperinflation of certain construction commodities and energy. The March 2007 submittal also incorporates budgetary quotes from vendors for the major pieces of equipment as well as noting the need for a non-recycling LSD due to the ash removal system's operation at a very high capacity factor. As depicted in Figure 3, a non-recycling LSD would eliminate slurry solids; instead the FGD solids (removed in the baghouse) are immediately disposed.

[9] EPA's BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

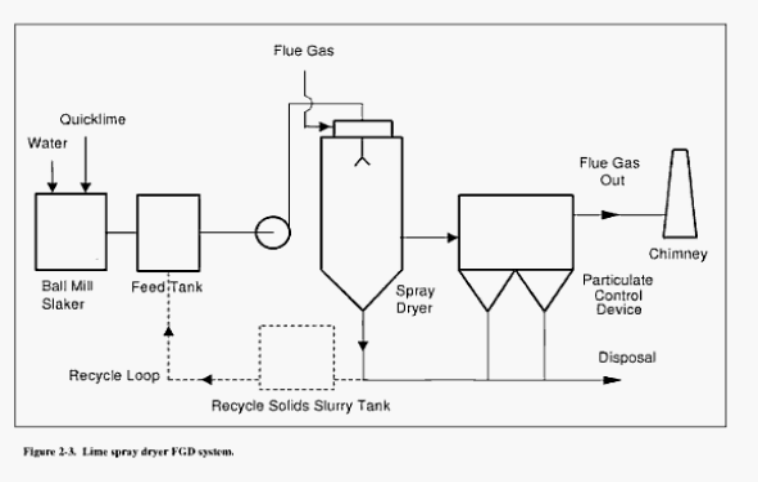


**Figure 3: Lime Spray Dryer (LSD) Schematic[10]**

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

*DSI:* CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[11] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

*Emission Limit Tightening*: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

[10] EPA, 2000. "Controlling $SO_2$ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 12.
[11] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[12], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants ($NO_x$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5. The Division modeled Drake Unit 5 for 0.12 lb/MMBtu as a theoretical examination of the potential impacts of lower emission limits on that unit.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| $SO_2$ BART Control Limit | Unit(s) | SO2 Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr $SO_2$ rates | 5 | 0.943 | Rocky Mountain National Park | 34 | --- | --- | 17 | --- | --- |
| | 6 | 0.997 | | | | | | | |
| | 7 | 0.994 | | | | | | | |
| DSI | 5 | 0.251 | | 34 | 32 | 2 | 17 | 14 | 3 |

[12] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 6 | 0.328 | | 34 | 32 | 2 | 17 | 14 | 3 |
| | 7 | 0.333 | | 34 | 31 | 3 | 17 | 13 | 4 |
| dry FGD (LSD) | 5 | 0.120 | | n/a | | | | | |
| | 6 | 0.120 | | 34 | 31 | 3 | 17 | 14 | 3 |
| | 7 | 0.120 | | 34 | 28 | 6 | 17 | 12 | 5 |
| dry FGD (LSD) | 6 | 0.100 | | 34 | 31 | 3 | 17 | 14 | 3 |
| | 7 | 0.100 | | 34 | 28 | 6 | 17 | 12 | 5 |
| dry FGD (LSD) | 6 | 0.070 | | 34 | 31 | 3 | 17 | 14 | 3 |
| | 7 | 0.070 | | 34 | 28 | 6 | 17 | 12 | 5 |
| Combo | 5 | 0.321 | | 34 | 1 | 33 | 17 | 0 | 17 |
| | 6 | 0.120 | | | | | | | |
| | 7 | 0.120 | | | | | | | |

**Table 15: Visibility Results – $SO_2$ Control Options**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hr $SO_2$ rates | 5 | 0.943 | 1.84 | --- | --- | --- |
| | 6 | 0.997 | | | | |
| | 7 | 0.994 | | | | |
| DSI | 5 | 0.251 | 1.72 | 0.12 | 6% | $14,673,714 |
| | 6 | 0.328 | 1.65 | 0.18 | 10% | $15,903,206 |
| | 7 | 0.333 | 1.55 | 0.29 | 16% | $16,765,140 |
| dry FGD (LSD) | 5 | 0.120 | n/a | | | |
| | 6 | 0.120 | 1.59 | 0.24 | 13% | $27,470,391 |
| | 7 | 0.120 | 1.45 | 0.39 | 21% | $22,697,484 |
| dry FGD (LSD) | 6 | 0.100 | 1.59 | 0.25 | 14% | n/a |
| | 7 | 0.100 | 1.44 | 0.40 | 22% | n/a |
| dry FGD (LSD) | 6 | 0.070 | 1.58 | 0.26 | 14% | $28,999,176 |
| | 7 | 0.070 | 1.42 | 0.41 | 22% | $23,967,026 |
| Combo | 5 | 0.321 | 0.25 | 1.59 | 86% | n/a |
| | 6 | 0.120 | | | | |
| | 7 | 0.120 | | | | |

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ BART for Unit 5 is the following $SO_2$ emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ BART for Unit 6 and Unit 7 is the following $SO_2$ emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)
Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSDs). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

The emission rates for Units 6 and 7 provide 85% $SO_2$ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton $SO_2$ removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton $SO_2$ removed; 0.39 deciview of improvement

## B. Filterable Particulate Matter ($PM_{10}$)

Drake Units 5, 6, and 7 are each equipped with reverse-air fabric filter baghouses to control $PM/PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP107 Condition 2.4.2 requires Units 5, 6, and 7 to conduct performance testing for $PM_{10}$ annually. While the emission in Condition 2.4 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 16 shows the most recent stack test data (June 14, 2006). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

**Table 16: Drake 2006 Stack Test Results**

| Pollutant | Unit 5 (lb/MMBtu) | Unit 6 (lb/MMBtu) | Unit 7 (lb/MMBtu) |
|---|---|---|---|
| Filterable $PM_{10}$ | 0.0132 | 0.0186 | 0.0111 |

| | | | |
|---|---|---|---|
| $PM_{10}$ Control efficiency | 98.6% | 98.3% | 99.0% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

The State determines that the existing regulatory emissions limit of 0.03 lb/MMBtu ($PM/PM_{10}$) for the three units represents the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for $PM/PM_{10}$ is not needed for Drake Units 5, 6, and 7.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies

CSU identified four $NO_x$ control options:

- Overfire air (OFA)
- Ultra-low $NO_x$ burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low $NO_x$ burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Selective Non-Catalytic Reduction (SNCR)
- Ultra-low $NO_x$ burners and Over-fire air (ULNB+OFA)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[13]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater $NO_x$ reduction for Units 5, 6, and 7. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

[13] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

***OFA:*** Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low $NO_x$ burners, such as those already present on Units 5, 6, and 7. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of $N_2$ rather than $NO_x$. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel $NO_x$ are formed[14]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal $NO_x$. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Units 5, 6, and 7.

***ULNBs:*** Each unit has low $NO_x$ burners installed, shown in Table 1 . These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased $NO_x$ emission reductions with these ultra-low $NO_x$ burners. ULNBs are a technically feasible option for Units 5, 6, and 7.

*ULNB+OFA*: Since ULNB and OFA are each technically feasible options and would be installed separately for Units 5, 6, and 7, it stands to reason that ULNB+OFA is technically feasible option for Units 5, 6, and 7.

***SCR:*** SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

While lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for CSU, a retrofit SCR, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 5, 6, and 7 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air

[14] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for $NO_x$ control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion

quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Drake Units 5, 6, and 7.

***ULNBs/SCR layered***: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Drake Units 5, 6, and 7. This scenario considers that less $NO_x$ would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for the three boilers at the Drake Plant.

***ECO®:*** The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[15] and thus, is considered technically infeasible.

***RRI:*** Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[16] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 5, 6, and 7.

***SNCR:*** Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's BART analysis because CSU asserts that SNCR achieves full-load $NO_x$ removal in the same range as ULNB at a higher levelized cost ($/ton $NO_x$ removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal $NO_x$ removal, resulting in $NO_x$ removal declines. The weighted average $NO_x$ removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a

[15] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[16] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

technically feasible alternative for Drake Units 5, 6, and 7. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a $NO_x$ control option for EGUs, so the Division included SNCR in the full four-factor analysis.

***Coal Reburn + SNCR:*** Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[17]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[18] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Drake Units 5, 6, and 7 to determine control efficiencies and annual reductions.

*OFA:* CSU estimated that overfire air, in conjunction with the existing low-$NO_x$ burners, is capable of reducing $NO_x$ emissions approximately an additional 20% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-$NO_x$ burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of $NO_x$ emissions.[19] The low $NO_x$ burners currently achieve about 50 – 56% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low $NO_x$ burners.[20] Therefore, the Division concurs with CSU's additional 20% $NO_x$ control estimate.

*ULNBs*: CSU asserts that additional $NO_x$ reductions of 20 – 30% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at the Drake boilers. These additional $NO_x$ reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled $NO_x$ emissions, which is consistent with a U.S. Department of Energy Study which estimated $NO_x$ emissions reductions between 75 – 85%.[21] Therefore, the Division concurs with CSU $NO_x$ reduction estimat3es for ULNBs.

[17] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers."
http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[18] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[19] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.
http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[21] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory.
http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf

*ULNB+OFA*: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. CSU noted in the February 2009 submittal that ULNB are assumed to achieve 20% efficiency *assuming* OFA is already installed (at 0.35 lb/MMBtu for each unit). The Division is employing a different baseline that CSU originally utilized (e.g. NOx emissions prior to consideration of OFA). The Division requested additional information from CSU to verify that the 20% ULNB assumption is still valid for all units. CSU noted that Units 6 and 7 will likely be able to achieve the 20% reduction (using the Division's higher NOx emission baseline). However, Unit 5 has an older technology coal mill and other technical issues and would not be able to achieve 20% reduction. Unit 5 has an older mill (ball-type pulverizers vs. the hammermills present at Units 6 and 7), which limits the level of coal fineness. In addition, Unit 5 is a smaller boiler than the other units. In light of these specific technical feasibility issues, the Division used 10% additional reduction efficiency for ULNBs for Unit 5. Therefore, the overall control efficiencies for ULNB+OFA in combination for the three units are 28% for Unit 5 and 36% for Units 6 and 7 respectively.

*SNCR:* Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[22] to conservatively approximate that the Drake boilers can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% $NO_x$ reduction using 2004 – 2005 baseline emissions (or 0.07 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions, but kept the resultant 0.07 lb/MMBtu constant. This control efficiency is consistent with EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[23,24]

*ULNBs/SCR layered approach:* CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce $NO_x$ entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same $NO_x$ emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 17 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 17: Drake Units 5, 6, and 7 $NO_x$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners (LNB) | 50 -56% | Y – installed |

[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[23] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[24] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

| | | |
|---|---|---|
| LNB + OFA | 60 – 81% | Y (LNBs are installed on each unit) |
| Overfire air (OFA) | 10 – 25% (alone) | Y |
| Ultra-low $NO_x$ burners (ULNBs) | 26 – 32% | Y |
| ULNB+OFA | 28 – 36% | Y |
| Selective non-catalytic reduction (SNCR) | ~ 30% | Y |
| Selective catalytic reduction (SCR) | 75 – 90% | Y |
| ULNB/SCR layered approach | 75 – 90% | Y |
| ECO® | n/a | N |
| RRI | n/a | N |
| Coal reburn +SNCR | n/a | N |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*OFA:* Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "$NO_x$ Controls for Existing Utility Boilers,"[25] OFA alone ranges from $410 - $1,100 per ton $NO_x$ reduced annually for units estimating 15 – 30% $NO_x$ control, which is within the range of Drake's estimated OFA $NO_x$ reductions (20%). The estimates in Table 18, Table 20, and Table 22 are within this range. Therefore, the Division concurs with the OFA cost estimates.

*ULNBs*: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 19, Table 21, and Table 23. The Division considers CSU's estimated costs more than

[25] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

reasonable, with ULNBs under $1,000/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[26, 27]

*ULNB+OFA*: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

*SNCR:* The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the Drake boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[28] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[29] Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[30]

The Division used information from a similar facility submittal to determine approximate SNCR costs for the Drake boilers since CSU did not have SNCR information.[31] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Drake boilers in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 5, 6, and 7 ranges from $2,700 to $4,400 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[32,33]

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[26] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/**nox**-2000.pdf

[27] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[28] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.

[29] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

[30] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[31] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

[32] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[33] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[34] Although the resulting cost estimates for the Drake boilers are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

*SCR:* CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving $NO_x$ emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[35,36] The SCR system estimates for the CSU Drake boilers range from approximately $5,000 - $7,100, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

*ULNBs/SCR layered approach:* CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 18, Table 20, and Table 22 illustrate resultant $NO_x$ emissions for each technically feasible control option. Table 19, Table 21, and Table 23 show the $NO_x$ control costs for each unit based on detailed cost analyses. The Division estimated resultant $NO_x$ using annual average reductions for tons of $NO_x$ reduced per year, as noted in Table 2. The Division's experience with power plants suggest that the maximum 30-day rolling average $NO_x$ emission rate is 5-15% higher than the annual average emission rate.

**Table 18: Drake Unit 5 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 768 | 0.38 | |
| Overfire air (OFA) | 20 | 615 | 0.30 | 0.35 |
| Ultra-low NOx burners (ULNBs) | 26 | 569 | 0.28 | 0.32 |
| ULNBs+OFA | 28 | 553 | 0.27 | 0.31 |
| Selective Non-Catalytic Reduction (SNCR) | 30 | 538 | 0.26 | 0.30 |

[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[35] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[36] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

| | | | | |
|---|---|---|---|---|
| ULNBs/SCR layered approach | 81.5 | 142 | 0.070 | 0.080 |
| Selective Catalytic Reduction (SCR) | 81.5 | 142 | 0.070 | 0.080 |

**Table 19: Drake Unit 5 $NO_x$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Overfire air (OFA) | 154 | $141,844 | $923 | $923 |
| Ultra-low NOx burners (ULNBs) | 200 | $147,000 | $736 | $112 |
| ULNBs+OFA | 215.2 | $288,844 | $1,342 | $9,230 |
| Selective Non-Catalytic Reduction (SNCR) | 231 | $1,011,324 | $4,387 | $47,011 |
| ULNB/SCR layered approach | 626 | $4,467,000 | $7,133 | $8,732 |
| Selective Catalytic Reduction (SCR) | 626 | $4,580,349 | $7,314 | --- |

**Table 20: Drake Unit 6 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,413 | 0.42 | |
| Overfire air (OFA) | 20 | 1,130 | 0.33 | 0.38 |
| Selective Non-Catalytic Reduction (SNCR) | 30 | 989 | 0.29 | 0.33 |
| Ultra-low NOx burners (ULNBs) | 32 | 961 | 0.28 | 0.32 |
| ULNBs+OFA | 36 | 904 | 0.27 | 0.31 |
| ULNBs/SCR layered approach | 83.2 | 237 | 0.070 | 0.080 |
| Selective Catalytic Reduction (SCR) | 83.2 | 237 | 0.070 | 0.080 |

**Table 21: Drake Unit 6 $NO_x$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Overfire air (OFA) | 283 | $104,951 | $371 | $371 |
| Selective Non-Catalytic Reduction (SNCR) | 424 | $1,208,302 | $2,851 | $7,810 |
| Ultra-low NOx burners (ULNBs) | 452 | $232,800 | $515 | ($34,525) |
| ULNBs+OFA | 509 | $337,751 | $664 | $1,857 |

| | | | | |
|---|---|---|---|---|
| ULNBs/SCR layered approach | 1,175 | $6,182,800 | $5,260 | $8,226 |
| Selective Catalytic Reduction (SCR) | 1,175 | $6,340,797 | $5,395 | --- |

**Table 22: Drake Unit 7 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 2,081 | 0.39 | |
| Overfire air (OFA) | 20 | 1,665 | 0.31 | 0.36 |
| Ultra-low NOx burners (ULNBs) | 28 | 1,498 | 0.28 | 0.33 |
| Selective Non-Catalytic Reduction (SNCR) | 30 | 1,457 | 0.28 | 0.32 |
| ULNBs+OFA | 36 | 1,332 | 0.25 | 0.29 |
| ULNBs/SCR layered approach | 80.1 | 372 | 0.070 | 0.080 |
| Selective Catalytic Reduction (SCR) | 80.1 | 372 | 0.070 | 0.081 |

**Table 23: Drake Unit 7 $NO_x$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Overfire air (OFA) | 416 | $75,217 | $181 | $181 |
| Ultra-low NOx burners (ULNBs) | 583 | $386,000 | $662 | $1,867 |
| Selective Non-Catalytic Reduction (SNCR) | 624 | $2,018,575 | $3,233 | $39,226 |
| ULNBs+OFA | 749 | $461,217 | $616 | ($12,473) |
| ULNBs/SCR layered approach | 1,708 | $8,196,000 | $4,797 | $5,698 |
| Selective Catalytic Reduction (SCR) | 1,708 | $8,510,067 | $4,981 | --- |

Energy and Non-Air Quality Impacts

*OFA:* Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

*ULNBs:* The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

*SNCR /SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For example, CSU estimates that on Drake 7, the power consumption for a SCR system will be over 700 kW. These energy requirements are moderate (0.5% of Drake 7's gross output).

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on an aqueous ammonia reagent versus an ammonia reagent.

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 24 shows the number of days pre- and post-control. Table 25 depicts the visibility results ($98^{th}$ percentile impact and improvements) as

well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[37], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $NO_x$ BART control technology on a given unit, emission rates for the other pollutants ($SO_2$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 24: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour NOx rates | 5 | 0.619 | Rocky Mountain National Park | 34 | --- | --- | 17 | --- | --- |
| | 6 | 0.827 | | | | | | | |
| | 7 | 0.710 | | | | | | | |
| NOx Control Scenario | 5 | 0.390 | | 34 | 34 | 0 | 17 | 15 | 2 |
| | 6 | 0.390 | | 34 | 31 | 3 | 17 | 14 | 3 |
| | 7 | 0.390 | | 34 | 31 | 3 | 17 | 14 | 3 |
| OFA | 5 | 0.300* | | n/a | | | | | |
| | 6 | 0.330* | | n/a | | | | | |
| | 7 | 0.310* | | n/a | | | | | |
| ULNBs | 5 | 0.280* | | n/a | | | | | |
| | 6 | 0.282* | | n/a | | | | | |
| | 7 | 0.283* | | n/a | | | | | |
| ULNBs+OFA | 5 | 0.272* | | n/a | | | | | |
| | 6 | 0.266* | | n/a | | | | | |

[37] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 7 | 0.251* | | n/a | | | | | | |
| SNCR | 5 | 0.265* | | n/a | | | | | | |
| | 6 | 0.291* | | n/a | | | | | | |
| | 7 | 0.275* | | n/a | | | | | | |
| NOx Control Scenario | 5 | 0.234 | | 34 | 34 | 0 | 17 | 14 | 3 | |
| | 6 | 0.234 | | 34 | 31 | 3 | 17 | 14 | 3 | |
| | 7 | 0.234 | | 34 | 28 | 6 | 17 | 14 | 3 | |
| SCR | 5 | 0.070 | | 34 | 32 | 2 | 17 | 14 | 3 | |
| | 6 | 0.070 | | 34 | 27 | 7 | 17 | 14 | 3 | |
| | 7 | 0.070 | | 34 | 26 | 8 | 17 | 13 | 4 | |
| Combo | 5 | 0.070 | | 34 | 1 | 33 | 17 | 0 | 17 | |
| | 6 | 0.070 | | | | | | | | |
| | 7 | 0.070 | | | | | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CSU Drake BART Modeling Summary" for more details.

**Table 25: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hour NOx rates | 5 | 0.619 | 1.84 | --- | --- | --- |
| | 6 | 0.827 | | | | |
| | 7 | 0.710 | | | | |
| NOx Control Scenario | 5 | 0.390 | 1.79 | 0.05 | 3% | n/a |
| | 6 | 0.390 | 1.68 | 0.16 | 9% | n/a |
| | 7 | 0.390 | 1.66 | 0.18 | 10% | n/a |
| OFA | 5 | 0.300* | 1.76 | 0.08 | 4% | $1,970,053 |
| | 6 | 0.330* | 1.66 | 0.18 | 10% | $583,061 |
| | 7 | 0.310* | 1.61 | 0.22 | 12% | $335,791 |
| ULNB | 5 | 0.280* | 1.76 | 0.08 | 4% | $1,934,212 |
| | 6 | 0.282* | 1.64 | 0.197 | 11% | $1,181,727 |
| | 7 | 0.283* | 1.60 | 0.24 | 13% | $1,615,062 |
| SNCR | 5 | 0.265* | 1.76 | 0.08 | 4% | $12,641,549 |
| | 6 | 0.291* | 1.64 | 0.19 | 11% | $6,228,362 |
| | 7 | 0.275* | 1.59 | 0.24 | 13% | $8,272,850 |
| ULNBs+OFA | 5 | 0.272* | 1.76 | 0.08 | 4% | $3,703,128 |
| | 6 | 0.266* | 1.63 | 0.20 | 11% | $1,663,798 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 7 | 0.251* | 1.58 | 0.26 | 14% | $1,794,618 |
| NOx Control Scenario | 5 | 0.234 | 1.75 | 0.24 | 5% | n/a |
| | 6 | 0.234 | 1.62 | 0.24 | 12% | n/a |
| | 7 | 0.234 | 1.57 | 0.24 | 15% | n/a |
| SCR | 5 | 0.070 | 1.71 | 0.12 | 7% | $36,024,194 |
| | 6 | 0.070 | 1.56 | 0.27 | 15% | $22,647,619 |
| | 7 | 0.070 | 1.47 | 0.37 | 20% | $22,091,644 |
| Combo | 5 | 0.070 | 0.25 | 1.59 | 86% | n/a |
| | 6 | 0.070 | | | | |
| | 7 | 0.070 | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CSU Drake BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $NO_x$ BART for Units 5, 6, and 7 is the following $NO_x$ emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling hour average)
Drake Unit 7: 0.29 lb/MMBtu (30-day rolling hour average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: 616 per ton NOx removed

The extremely low dollars per ton control costs, leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement does not meet the criteria guidance described in Chapter 6.4.3 of the Regional Haze SIP (*e.g.* less than 0.50 Δdv)

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Public Service Company – Hayden Station**

## I. Source Description

Owner/Operator: Public Service Company
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): Unit 1: 10100222 Unit 2: 10100226
Boiler Type: Pulverized Coal, Dry-Bottom, Front-Fired, firing coal (Unit 1 a)
Pulverized Coal, Dry Bottom, Tangentially-Fired, firing coal (unit 2)

The facility is located four miles east of Hayden, Colorado at 13125 U.S. Highway 40 in Routt County. This facility consists of two (2) steam driven turbine/generator units (Units 1 and 2) and the associated equipment needed for generating electricity. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers. Only Units 1 and 2 are BART-eligible. Table 1 below lists the units at Public Service Company Hayden Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

**Table 1: Hayden Boilers Technical Information**

| | Unit 1 | Unit 2 |
|---|---|---|
| Placed in Service | July 1965 | 1976 |
| Boiler Rating, MMBtu/Hr for coal | 1,963 | 2,712 |
| Electrical Power Rating, Gross Megawatts | 190 | 275 |
| Description | Riley-Stoker Pulverized Coal Front Fired Dry Bottom, firing coal with natural gas and No. 2 fuel oil used for startup, shutdown and/or flame stabilization. | Combustion Engineering Pulverized Coal Tangentially Fired Dry Bottom, firing coal with No. 2 fuel oil used for startup, shutdown, and/or flame stabilization. |
| Air Pollution Control Equipment | $PM/PM_{10}$ - Reverse-Air Fabric Filter Baghouse<br>$NO_x$ – Low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Lime Spray Dryer | $PM/PM_{10}$ – Reverse-Air Fabric Filter Baghouse<br>$NO_x$ – Low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Lime Spray Dryer |

| | All equipment commenced operation in December 1998 | All equipment commenced operation in October – December 1999 |
|---|---|---|
| Emissions Reduction (%)* | $NO_x$ – 54.1%<br>$SO_2$ – 82.0%<br>PM – 99.7%<br>$PM_{10}$ – 98.8% | $NO_x$ – 33.3%<br>$SO_2$ – 79.6%<br>PM – 99.7%<br>$PM_{10}$ – 98.9% |

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for $PM/PM_{10}$. For $NO_x$ and $SO_2$ estimates, CAMD data was used to calculate reductions. See "Hayden APCD Technical Analysis" for further details. Not based on actual testing.

Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to Division requests, PSCo submitted additional information on May 25 and July 14, 2010. The submittals are included as "PSCo BART Submittals".

## II. Emissions for Units 1 & 2

PSCo estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline Emissions", to be conservative, was the average of two previous years (2004, 2005) of emissions data in the September 14, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

**Table 2: PSCo Hayden Units 1 & 2 Emissions**

| Pollutant | Unit 1 | | Unit 2 | |
|---|---|---|---|---|
| | Annual Emissions* (tpy) | Annual emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Annual emissions** (lb/MMBtu) |
| $NO_x$ | 3,750 | 0.415 | 3,743 | 0.320 |
| $SO_2$ | 1,172 | 0.131 | 1,469 | 0.127 |
| $PM_{10}$ | 88.0 | 0.006*** | 109.3 | 0.004*** |

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions.
***The $PM_{10}$ emission rate is determined from the latest Title V permit compliance stack test (June 2009). These values are as follows: Hayden Unit 1: 0.006 lb/MMBtu Hayden Unit 2: 0.004 lb/MMBtu

## III. Units Evaluated for Control

PSCo notes that the Hayden boilers burn Colorado coal that primarily comes from two different mines in northwestern Colorado, the Twenty Mile Mine and the ColoWyo Mine. Coal characteristics are very similar from both of these mines. However, the ColoWyo coal is ranked as sub-bituminous while the Twenty Mile coal is ranked as bituminous (ASTM Method 388). However, PSCo performed an analysis using the Electric Power Research Institute ("EPRI") NOx/LOI Predictor software program (Version 2.1) to demonstrate that the more appropriate rating for ColoWyo coal is bituminous. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

**Table 3: Hayden Station Coal Specifications (2004 – 2005)**

| Coal Mine/Region | Colowyo | Twentymile |
|---|---|---|
| Coal Rank Classification | Sub-bituminous, Class A | Bituminous |
| As Received Analysis | | |
| $H_2O$ (Moisture %) | 16.8 | 9.8 |
| Ash (%) | 5.82 | 9.5 |
| Sulfur (%) | 0.36 | 0.49 |
| Nitrogen (%) | 1.33 | 1.65 |
| Heating Value (HHV Btu/lb) | 10,450 | 11,350 |
| EPRI Model $NO_x$ Prediction (lb/MMBtu) | 0.46 | 0.39 |

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

**Table 4: Uncontrolled emission factors for PSCo Hayden BART-eligible sources[1]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Hayden Unit 1 | 22** | 18.6 | 95 | 21.9 |
| Hayden Unit 2 | 15** | 18.6 | 95 | 21.9 |

*$SO_2$ and $PM/PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 3.

**Assumed no low-$NO_x$ burners.

## IV. BART Evaluation of Units 1 and 2

### A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Hayden Units 1 and 2 if technically feasible. These upgrades include:
-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system
-Additional equipment and maintenance: In the May 25, 2010 response to the Division, PSCo noted that Hayden Units 1 and 2 could potentially achieve a new reduced 30-day average emission rate limit of 0.13 lbs/MMBtu by conducting changes to the dry scrubber systems, so this option will be evaluated as part of possible semi-dry FGD upgrades.

The current Operating Permit limits are depicted in Table 5.

**Table 5: Hayden Units 1 & 2 $SO_2$ Operating Permit Limits**

| | $SO_2$ limits (lb/MMBtu) | | | Reduction (%) Required |
|---|---|---|---|---|
| | 3-hr rolling | 30-day rolling | 90-day rolling | 30-day rolling |
| Units 1 & 2 | 1.2 | 0.160 | 0.130 | 82 (rounded) |

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an $SO_2$ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the LSDs installed on Hayden Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Dry FGD Upgrades:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

PSCo installed lime spray dryers (LSDs) in connection with baghouses on Hayden Units 1 and 2 1998 and 1999, respectively. PSCo notes that both of these dryers currently achieve greater than 80% removal, with actual annual averages of 0.13 lbs $SO_2$/MMBtu (each unit) in comparison with the permit limits[4] depicted in Table 5. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits.

At the Division's request, PSCo submitted a $SO_2$ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the lime spray dryer systems at Hayden Station. Hayden's Babcock and Wilcox (B&W) lime spray dryers that use a single atomizer per scrubber module design that sprays a mixture of lime and recycled ash into the flue gas. This atomized mist then dries, reacts with $SO_2$ in the flue gas and is collected in the baghouse.

PSCo examined potential upgrades to the Hayden dry scrubbers, with the following results:

-*Use of performance additives:* The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous $SO_2$. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same $SO_2$ reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in $SO_2$ removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase $SO_2$ removal and therefore warrants no further consideration.

-*Use of more reactive sorbent:* All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Hayden.

[4] Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove $SO_2$. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied by Rockwell and used rotary atomizers. The unit was designed to obtain 70% $SO_2$ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to $NO_2$ due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher $SO_2$ removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes $SO_2$ removal; there are no known acceptable reagents without side effects that would allow additional $SO_2$ removal in the dry scrubbing systems present at Hayden Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

-*Increase the pulverization level of sorbent:* The Hayden dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. There have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. PSCO's experience is that there is no $SO_2$ removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. Since PSCo already uses the best available grinding technologies, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher $SO_2$ removal.

-*Engineering redesign of atomizer or slurry injection system:* The Hayden dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both $SO_2$ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve $SO_2$ removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved $SO_2$ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the $SO_2$ removal level, although some have improved wear life and reduced maintenance costs.

However, PSCo provided to the Division upon additional request (July 14, 2010) additional information stating that an additional scrubber module (i.e. atomizer) would be required for each unit as well as additional spare parts and maintenance personnel in order to meet a lower emission limit. Therefore, this option is technically feasible.

-*Additional equipment and maintenance*: PSCo reviewed actual operating experience on Hayden along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect $SO_2$ control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, $SO_2$ emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control $SO_2$ by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall $SO_2$ control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

Based on a review of actual operating data and the factors noted above that affect short-term average $SO_2$ emission rates, PSCo believes Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit of 0.13 lbs/MMBtu as BART. This is currently the 90-day average emission limit for these units. In order to meet this lower limit on a 30-day average basis, the plant needs to purchase additional spare atomizer parts and increase annual operating and maintenance due to increased labor and reagent requirements.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. In the Division's experience, 30-day $SO_2$ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected an annual average emission rate at 5% for Hayden to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by PSCo as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT $SO_2$ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

*Engineering redesign of atomizer or slurry injection system:* At the Division's request, PSCo sent cost information regarding the requirements for an additional scrubber module on July 14, 2010 in order to meet a $SO_2$ 30-day rolling emission limit of 0.08 lb/MMBtu, or 90% control efficiency (pre-control). This upgrade/redesign will result in control efficiencies of 41.7% and 40.1% beyond the current reductions shown in Table 1 on Units 1 and 2, respectively. Using this information, the Division calculated the resultant control effectiveness using the baseline and annual emissions for each unit. See "Hayden APCD Technical Analysis" for more information.

*Dry FGD Upgrade – Additional equipment and maintenance:* To evaluate the control effectiveness of tightening the 30-day rolling emission limits on Hayden Units 1 and 2, the Division used the annual baseline emissions, the average annual operating hours (2006 – 2008), and the daily heat input (MMBtu/day) to determine the emission rates at 0.13 lb/MMBtu and calculated the resultant control effectiveness and annual emissions for each unit.

**Table 6** summarizes each available technology and technical feasibility for $SO_2$ control.

**Table 6: Hayden Units 1 and 2 $SO_2$ Technology Options and Technical Feasibility**

| Technology | | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|---|
| Dry FGD Upgrades | | | |
| | Use of performance additives | n/a | N |
| | Use of more reactive sorbent | n/a | N |
| | Increase pulverization level of sorbent | n/a | N |
| | Engineering redesign of atomizer or slurry injection system | ~40 – 42% | Y |
| | Additional equipment and maintenance | ~3 - 5% | Y |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*Engineering redesign of atomizer or slurry injection system*: The Division calculated cost estimates for an additional scrubber module – based on total capital and operating and maintenance costs provided in PSCo's July 14, 2010 letter. PSCo stated that Hayden Station will need for an additional module on each unit as well as estimated spare parts and additional maintenance personnel (i.e. O&M costs). PSCo estimated capital costs for Unit 1 at $37,000,000 and Unit 2 at $43,000,000 and operating & maintenance costs at $650,000 and $750,000 for Units 1 and 2, respectively. These costs are determined based on meeting a more stringent 30-day rolling limit of 0.08 lb/MMBtu for each unit.

*Dry FGD Upgrade – Additional equipment and maintenance:* The Division calculated cost estimates for dry FGD upgrade – additional equipment and maintenance – based on total capital and operating and maintenance costs provided in PSCO's May 25, 2010 letter. PSCo stated that Hayden Station will need spare atomizer parts at a cost of $330,000 along with increased annual operating and maintenance costs of $220,000 per year for reagent and labor to meet the more

stringent 30-day rolling $SO_2$ emission limit of 0.13 lbs/MMBtu. This cost analysis was conducted to demonstrate the impact of meeting the more stringent limit only. Table 7, Table 8, Table 9, and Table 10 show the $SO_2$ control cost per unit.

**Table 7: Hayden Unit 1 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,172 | 0.131 | |
| Dry FGD Upgrade – Additional Equipment and Maintenance | 5.2% | 1,111 | 0.124 | 0.130 |
| Additional Scrubber Module | 41.7% | 684 | 0.076 | 0.080 |

**Table 8: Hayden Unit 2 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,469 | 0.127 | |
| Dry FGD Upgrade – Additional Equipment and Maintenance | 2.7% | 1,430 | 0.124 | 0.130 |
| Additional Scrubber Module | 40.1% | 880 | 0.076 | 0.080 |

**Table 9: Hayden Unit 1 $SO_2$ Cost Effectiveness**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Dry FGD Upgrade – Additional Equipment and Maintenance | 61 | $141,150 | $2,317 | $2,317 |
| Additional Scrubber Module | 488 | $4,142,538 | $8,490 | $9,370 |

**Table 10: Hayden Unit 2 $SO_2$ Cost Effectiveness**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Dry FGD Upgrade – Additional Equipment and Maintenance | 39 | $141,150 | $3,626 | $3,626 |
| Additional Scrubber Module | 589 | $4,808,896 | $8,164 | $8,485 |

Energy and Non-Air Quality Impacts

There are no energy and non-air quality impacts related to tightening the emission limit for $SO_2$ beyond the acquisition of additional reagent. Thus, this factor does not influence the selection of controls.

Remaining Useful Life

PSCo asserts that the remaining useful life of Hayden Units 1 and 2 are each in excess of 20 year, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. Table 12 depicts the visibility results ($98^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[5], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants ($NO_x$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

[5] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 11: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δ days | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr $SO_2$ rates | 1 | 0.339 | Rocky Mountain National Park | 236 | --- | --- | 155 | --- | --- |
| | 2 | 0.402 | | | | | | | |
| Dry FGD Upgrade | 1 | 0.160* | | n/a | | | | | |
| | 2 | 0.160* | | n/a | | | | | |
| Dry FGD Upgrade | 1 | 0.130 | | 236 | 228 | 8 | 155 | 147 | 8 |
| | 2 | 0.130 | | 236 | 224 | 12 | 155 | 143 | 12 |
| Additional Scrubber Module | 1 | 0.100 | | 236 | 228 | 8 | 155 | 146 | 9 |
| | 2 | 0.100 | | 236 | 223 | 13 | 155 | 143 | 12 |
| Additional Scrubber Module | 1 | 0.070 | | 236 | 228 | 8 | 155 | 146 | 9 |
| | 2 | 0.070 | | 236 | 223 | 13 | 155 | 142 | 13 |
| Combo | 1 | 0.070 | | | | | | | |
| | 2 | 0.070 | | 236 | 57 | 179 | 155 | 6 | 149 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

**Table 12: Visibility Results – $SO_2$ Control Options**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hr $SO_2$ rates | 1 | 0.339 | 3.627 | --- | --- | --- |
| | 2 | 0.402 | | | | |
| Dry FGD Upgrade | 1 | 0.160* | 3.540 | 0.09 | 2% | n/a |
| | 2 | 0.160* | 3.445 | 0.18 | 5% | n/a |
| Dry FGD Upgrade | 1 | 0.130 | 3.525 | 0.10 | 3% | $1,383,820 |
| | 2 | 0.130 | 3.422 | 0.21 | 6% | $688,535 |
| Additional Scrubber Module | 1 | 0.100 | 3.505 | 0.12 | 3% | $33,955,232 |
| | 2 | 0.100 | 3.395 | 0.23 | 6% | $20,727,999 |
| Additional Scrubber Module | 1 | 0.070 | 3.485 | 0.14 | 4% | n/a |
| | 2 | 0.070 | 3.367 | 0.26 | 7% | n/a |

| | | | | | | |
|---|---|---|---|---|---|---|
| Combo | 1<br>2 | 0.120<br>0.120 | 0.91 | 2.72 | 75% | n/a |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ BART the following $SO_2$ emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSDs). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

## B. Filterable Particulate Matter ($PM_{10}$)

Hayden Units 1 and 2 are each equipped with reverse-air fabric filter baghouses to control $PM/PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 13 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >99% control. The Title V permit limit is 0.03 lb/MMBtu. The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

**Table 13: Hayden Units 1 and 2 Stack Test Results (2009)**

| Pollutant | Unit 1 (lb/MMBtu) | Unit 2 (lb/MMBtu) |
|---|---|---|
| Filterable $PM_{10}$ | 0.006 | 0.004 |
| $PM_{10}$ Control efficiency | 99.85% | 99.91% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.V.8.c.ii(2).

The state has determined that the emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this control technology and emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for $PM/PM_{10}$ is not needed for Hayden Units 1 and 2.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies
PSCo identified three options for $NO_x$ control:
Low $NO_x$ burners (next generation)
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Rotating overfire Air (ROFA)
Separated overfire Air (SOFA)
Low $NO_x$ Burners (LNB)
LNB + SOFA
Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options
*Low $NO_x$ burners (PSCo – LNB):* PSCo evaluated low $NO_x$ burner upgrades for Hayden Units 1 and 2, completing studies in July 2006. Units 1 and 2 currently have first-generation low $NO_x$ burners and over-fire air systems. The combustion modifications include upgrades to these existing low $NO_x$ burners rather than complete burner replacements. In addition, changes to the over-fire air systems were also needed to achieve further $NO_x$ reductions on these units. LNB upgrades are technically feasible for Hayden Units 1 and 2.

*SNCR:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent

reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Hayden Units 1 and 2.

*SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

While a lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for Hayden, two retrofit SCR systems, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative. PSCo economically evaluated a high-dust SCR arrangement. SCR is a technically feasible alternative for Hayden Units 1 and 2.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[6] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[7] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

*LNB/ROFA®/SOFA/LNB+SOFA:* Hayden Units 1 and 2 are already equipped with low $NO_x$ burners with over-fire air (LNB+OFA)as part of a consent decree entered by the District Court on August 19,1996, Civil Action 93-B-1749 and adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements," dated August 15, 1996. Table 1 illustrates that these systems achieve 49.5% and 43.3% $NO_x$ reductions (based on actual emissions) on Units 1 and 2, respectively.

ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to

[6] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[7] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[8]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+SOFA and is not expected to increase emissions reductions for Hayden Units 1 and 2. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+SOFA baseline for these units, ROFA® technology is not considered further in this analysis.

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[9]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals[10], determined that 30-day $NO_x$ rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. The Division projected an annual average emission rate at 15% for Hayden to determine control efficiencies and annual reductions.

*Low $NO_x$ burners (PSCo – LNB):* PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.24 lb/MMBtu respectively with upgraded low $NO_x$ burner systems. The baselines from Table 2 show that Hayden Unit 1 baseline $NO_x$ emissions are 0.415 lb/MMBtu and Unit 2 baseline $NO_x$ is 0.320 lb/MMBtu. Therefore, the control effectiveness for upgraded low $NO_x$ systems for Unit 1 is 37.1% and Unit 2 is 34.8%. As shown in Table 1, the current low-$NO_x$ burners with overfire air systems achieve 54.1% and 31.3% control respectively. These upgrade control estimates are greater than EPA's AP-42 emission factor table, which estimate LNB with OFA as achieving 40 – 60% reduction.[11] In a recent AWMA study, wall-fired boilers burning sub-bituminous coal fitted with LNB+OFA system achieved $NO_x$ reductions from 40 – 80.9% (similar to Hayden Unit 1). Tangential-fired boilers achieved $NO_x$ reductions ranging from 11.3 – 74.4%.[12] With such wide control

[8] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html
[9] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[10] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[11] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[12] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

efficiency ranges, the Division concludes that the 88.9% and 66.1% (pre-control) reductions estimated by PSCo are reasonable.

*SNCR:* PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.21 lb/MMBtu respectively by installing SNCR on each boiler. Therefore, the control effectiveness for SNCR on Unit 1 is 37.1% and Unit 2 is 43.0%. These control effectiveness estimate is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers. Control effectiveness has been historically noted to be lower for wall fired boilers similar to Unit 1. Therefore, the Division concludes that the reductions estimated by PSCo are reasonable.

*SCR:* PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.08 lb/MMBtu and 0.07 lb/MMBtu respectively by installing SCR on each boiler. Therefore, the control effectiveness for SCR on Unit 1 is 83.2% and Unit 2 is 81.0%. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[13,14]

Table 14 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 14: Hayden Units 1 and 2 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burner (LNB) Upgrade | ~35 - 37% | Y |
| SNCR | 20 – 50% | Y |
| SCR | 75 – 90% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Low $NO_x$ Burners (LNB) | 10-30% | Y – installed |
| LNB + OFA | 25-45% | Y – installed |
| Air Staging – overfire air (OFA) | 5-40% | Y – installed |
| Rotating overfire air (ROFA) | 45 – 65% | N |
| Coal reburn+SNCR | n/a | N |

[13] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[14] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

*Low $NO_x$ burners (PSCo – LNB)/SNCR/SCR:* PSCo completed engineering studies in July 2006 to evaluate the cost of combustion controls on Hayden Units 1 and 2. These cost estimates, in 2006 dollars, were based on vendor data and not on actual bids with performance guarantees. PSCo used the Coal Utility Environmental Cost Workbook (CUECost) to develop cost estimates for capital and annual costs ,an EPA-approved methodology to estimate rough order-of-magnitude (ROM) cost estimates for air pollution control systems installed on coal-fired power plants (± 30%).[15] PSCo provided CUECost input files at the Division's request on April 20, 2010. PSCo used this program for LNB, SNCR, and SCR system estimates. The Division concurs that CUECost is an appropriate methodology for determining cost effectiveness regarding these control technologies.

*LNB:* In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 11.7% is consistent with an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments. [16] Therefore, the Division concludes that PSCo's estimates for LNBs are reasonable.

*SNCR:* A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[17] The PSCo-estimated SNCR costs for operating expenses are 74% and 77% for Hayden Units 1 and 2 respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[18]

The cost effectiveness for SNCR on Units 1 and 2 is about $1,000 and $1,200 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 2) achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced,

[15] 2009, Yelverton, William H. "Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0. Prepared by: ARCADIS, 4915 Prospectus Drive, Suite F, Durham, NC 27713. Prepared for: U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC 27711.
[16] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.
[17] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[18] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

depending on initial capital costs and capacity factor.[19,20] This same study estimate SNCR retrofits on wall fired boilers (similar to Unit 1) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor. It should be noted that PSCo is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[21] PSCo's estimates are within this range. Therefore, the Division concludes that PSCo's cost estimates for SNCR are reasonable.

*SCR:* Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[22,23] In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 17% is higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.[24] However, PSCo's cost estimates are within the NESCAUM study ranges, so the Division concludes that PSCo's cost estimates for SCR are reasonable.

Table 15, Table 16, Table 17, and Table 18 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 15: Hayden Unit 1 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 3,750 | 0.415 | |
| LNB* | 37.1 | 2,359 | 0.261 | 0.300 |
| SNCR* | 37.1 | 2,359 | 0.261 | 0.300 |
| SCR** | 83.2 | 630 | 0.070 | 0.080 |

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

[19] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[20] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[21] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[22] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[23] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[24] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

**Table 16: Hayden Unit 2 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 3,743 | 0.320 | |
| LNB* | 34.8 | 2,441 | 0.209 | 0.240 |
| SNCR* | 43.0 | 2,134 | 0.183 | 0.210 |
| SCR** | 81.0 | 711 | 0.061 | 0.070 |

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates
**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

**Table 17: Hayden Unit 1 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| LNB | 1,391 | $572,010 | $411 | $411 |
| SNCR | 1,391 | $1,353,500 | $973 | --- |
| SCR | 3,120 | $10,560,612 | $3,385 | $5,326 |

**Table 18: Hayden Unit 2$NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| LNB | 1,303 | $992,729 | $762 | $762 |
| SNCR | 1,610 | $1,893,258 | $1,176 | $2,934 |
| SCR | 3,032 | $12,321,491 | $4,064 | $7,331 |

Energy and Non-Air Quality Impacts

*LNB:* There are no known non-air quality impacts associated with upgrades on low-$NO_x$ burner systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/ SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. These energy requirements are moderate.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

PSCo asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[25], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $NO_x$ BART control technology on a given unit, emission rates for the other pollutants ($SO_2$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART

[25] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with $NO_x$ emissions at 0.07 lb/MMBtu and $SO_2$ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr NOx rates | 1 | 0.610 | Mt. Zirkel Wilderness Area | 236 | --- | --- | 155 | --- | --- |
| | 2 | 0.367 | | | | | | | |
| NOx Scenario | 1 | 0.390 | | 236 | 227 | 9 | 155 | 131 | 24 |
| | 2 | 0.280 | | 236 | 230 | 6 | 155 | 144 | 11 |
| NOx Scenario | 1 | 0.300 | | 236 | 218 | 18 | 155 | 125 | 30 |
| | 2 | 0.210 | | 236 | 226 | 10 | 155 | 137 | 18 |
| LNB | 1 | 0.261* | | n/a | | | | | |
| | 2 | 0.209* | | n/a | | | | | |
| SNCR | 1 | 0.261* | | n/a | | | | | |
| | 2 | 0.183* | | n/a | | | | | |
| SCR | 1 | 0.070 | | 236 | 188 | 48 | 155 | 91 | 64 |
| | 2 | 0.070 | | 236 | 213 | 23 | 155 | 116 | 39 |
| Combo | 1 | 0.070 | | 236 | 57 | 179 | 155 | 6 | 149 |
| | 2 | 0.070 | | | | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

**Table 20: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu)* | Proposed Limit (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (deciviews) | (deciviews) | (%) | ($/deciview) |
| Max 24-hr | 1 | 0.610 | 3.63 | --- | --- | --- |

| | | | | | | |
|---|---|---|---|---|---|---|
| NOx rates | 2 | 0.367 | | | | |
| NOx Scenario | 1 | 0.390 | 3.13 | 0.50 | 14% | n/a |
| | 2 | 0.280 | 3.42 | 0.20 | 6% | n/a |
| NOx Scenario | 1 | 0.300 | 3.02 | 0.60 | 17% | n/a |
| | 2 | 0.210 | 3.23 | 0.40 | 11% | n/a |
| LNB | 1 | 0.261* | 2.94 | 0.69 | 19% | $832,621 |
| | 2 | 0.209* | 3.23 | 0.40 | 11% | $2,500,576 |
| SNCR | 1 | 0.261* | 2.94 | 0.69 | 19% | $1,970,161 |
| | 2 | 0.183* | 3.15 | 0.48 | 13% | $3,969,094 |
| SCR | 1 | 0.070 | 2.51 | 1.12 | 31% | $9,462,914 |
| | 2 | 0.070 | 2.77 | 0.85 | 24% | $14,427,975 |
| Combo | 1 | 0.070 | 0.91 | 2.72 | 75% | n/a |
| | 2 | 0.070 | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that $NO_x$ BART is the following $NO_x$ emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan:

- Unit 1: $3,385 per ton $NO_x$ removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton $NO_x$ removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The $NO_x$ emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

# APPENDIX D

## *Regional Haze State Implementation Plan*

***Technical Support for the Reasonable Progress Determinations***

**Reasonable Progress (RP) Four-Factor Analysis of Control Options**
**For**
**Colorado Energy Nations, Golden, Colorado**

I. Source Description

Owner/Operator: Colorado Energy Nations (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 1 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
Boiler 2 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
Boiler 3 – Pulverized Coal Spreader Stoker (SCC: 10200224)
Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek and US Highway 58 borders the northern side of the CENC site.




**Figure 1: CENC facility Aerial Perspective**

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operate in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/$PM_{10}$ by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the CENC facility, and information about similar facilities to determine RP for $NO_x$, $SO_2$, and $PM_{10}$. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is

located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010. Table 1 depicts technical information for Boiler 3 at the CENC facility.

**Table 1: CENC Boiler 3 RP-eligible Emission Controls and Reduction (%)**

| | Unit B003 |
|---|---|
| Placed in Service | 1962; updated to coal in 1981 |
| Boiler Rating, MMBtu/Hr for coal | 225 |
| Electrical Power Rating, Gross Megawatts | 24 |
| Description | Combustion Engineering Model CE-VU40 225 MMBtu/hr (coal), traveling grate stoker, firing only coal for primary fuel and fuel oil/coal for a cold start |
| Air Pollution Control Equipment | Carter Day fabric filter baghouse with 4 compartments |
| Emissions Reduction (%) | $NO_x$ – None<br>$SO_2$ – None<br>$PM/PM_{10}$ – 93+% |

## II. Source Emissions

CENC estimated that a realistic depiction of annual emissions for Boiler 3, or "Baseline Emissions" was the years 2006 – 2008. CENC determined that the maximum year within this scope was 2006, since it had the highest capacity factor and heat input.

Table 2 summarizes the $NO_x$, $SO_2$, and PM actual emissions averaged over the 2006 – 2008 timeframe for the facility. Table 3 summarizes each unit at the facility and applicable $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

submitted by the facility and as applicable, EPA's CAMD Database (Boilers 4 and 5).

**Table 2: Summary of 2006 - 2008 Averaged Emissions – CENC Facility**

| $NO_x$ (tons/year) | $SO_2$ (tons/year) | $PM_{10}$ (tons/year) |
|---|---|---|
| 1,512 | 2,433 | 38 |

**Table 3: Summary of 2006 - 2008 Averaged Emissions by Unit - CENC Facility**

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| *Boiler #1 (288 MMBtu/hour – natural gas fired)* | *$SO_2$ (tons)* | *0.1* | *0.1* | *0.1* | *0.1* |
| | *$SO_2$ (lb/ MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *30.8* | *23.9* | *30.3* | *28.3* |
| | *$NO_x$ (lb/ MMBtu)* | *0.02* | *0.02* | *0.02* | *0.02* |
| | *$PM_{10}$ (tons)* | *0.8* | *0.7* | *0.8* | *0.7* |
| | *$PM_{10}$ (lb/ MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| *Boiler # 2 (288 MMBtu/hour – natural gas fired)* | *$SO_2$ (tons)* | *0.1* | *0.0* | *0.1* | *0.1* |
| | *$SO_2$ (lb/ MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *32.4* | *10.4* | *27.6* | *23.5* |
| | *$NO_x$ (lb/ MMBtu)* | *0.03* | *0.01* | *0.02* | *0.02* |
| | *$PM_{10}$ (tons)* | *0.9* | *0.3* | *0.7* | *0.6* |
| | *$PM_{10}$ (lb/ MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| Boiler #3 (225 MMBtu/hour – coal fired) | $SO_2$ (tons) | 264 | 205 | 267 | 245 |
| | $SO_2$ (lb/ MMBtu) | 0.27 | 0.21 | 0.27 | 0.25 |
| | $NO_x$ (tons) | 185 | 150 | 170 | 168 |
| | $NO_x$ (lb/ MMBtu) | 0.19 | 0.15 | 0.17 | 0.17 |
| | $PM_{10}$ (tons) | 2.3 | 1.9 | 2.1 | 2.1 |
| | $PM_{10}$ (lb/ MMBtu) | 0.00 | 0.00 | 0.00 | 0.00 |
| Boiler #4 – (360 MMBtu/hour – coal fired) | $SO_2$ (tons) | 764 | 815 | 763 | 781 |
| | $SO_2$ (lb/ MMBtu) | 0.48 | 0.52 | 0.48 | 0.49 |
| | $NO_x$ (tons) | 637 | 589 | 575 | 600 |
| | $NO_x$ (lb/ MMBtu) | 0.40 | 0.37 | 0.37 | 0.38 |
| | $PM_{10}$ (tons) | 10.9 | 10.0 | 10.4 | 10.4 |
| | $PM_{10}$ (lb/ MMBtu) | 0.01 | 0.01 | 0.01 | 0.01 |
| Boiler #5 – (650 MMBtu/hour – coal fired) | $SO_2$ (tons) | 1,598 | 1,333 | 1,289 | 1,407 |
| | $SO_2$ (lb/ MMBtu) | 0.56 | 0.47 | 0.45 | 0.49 |
| | $NO_x$ (tons) | 900 | 614 | 559 | 691 |
| | $NO_x$ (lb/ MMBtu) | 0.32 | 0.22 | 0.20 | 0.25 |
| | $PM_{10}$ (tons) | 21 | 17 | 16 | 18 |
| | $PM_{10}$ (lb/ MMBtu) | 0.01 | 0.01 | 0.01 | 0.01 |
| *P005 – Coal Unloading and Conveying* | *$PM_{10}$ (tons)* | *0.03* | *0.03* | *0.03* | *0.03* |
| *P007 – Boiler #5 Silos – coal conveyor to Unit 5 silos* | *$PM_{10}$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| *P008 – Ash Handling – 11, 12, 13 – general ash silo* | *$PM_{10}$ (tons)* | *5.57* | *5.57* | *5.38* | *5.51* |
| *P009 – Boiler #3 Silos – coal conveyor to Unit 5 silos* | *$PM_{10}$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| *P010 – Ash Handling – Boiler #4 & #5 fly ash* | *$PM_{10}$ (tons)* | *0.02* | *0.02* | *0.02* | *0.02* |

| | | | | | |
|---|---|---|---|---|---|
| *collection* | | | | | |
| *P011 – Ash Handling – Fly ash silo loadout* | *$PM_{10}$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| *P012 – Ash Handling – Fly ash silo bin vent* | *$PM_{10}$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| *P013 – Diesel Air Compressors – GM diesel engine for backup operation of air compressor* | *$SO_2$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$PM_{10}$ (tons)* | *0.00* | *0.00* | *0.00* | *0.00* |

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day $NO_x$ rolling average is likely about 0.44 lbs/MMBtu for Boiler 4 and 0.29 lbs/MMBtu for Boiler 5).

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Boiler 3 currently has grandfathered status for State construction permits. This boiler is included in the current Title V permit, but does not currently have fuel usage or emission limitations for $NO_x$, PM, or $SO_2$. This boiler is subject to opacity requirements under Colorado Regulation No. 1, Section II.A.1 and a sulfur dioxide limit of 1.8 lbs/MMBtu when burning coal. Boiler 3 has a PM emission rate limit of 0.122 lbs/MMBtu and is controlled with a baghouse that was installed in the early 1980s. In addition to not utilizing a CEMS, a sophisticated automatic Data Acquisition System for control parameters, such as fuel usage, is not installed. The actual NOx emissions is based on AP-42 factors applicable to the coal type (bituminous, sub-bituminous, etc.) and coal usage based on rail car / truck unloading records. This AP-42 factor has a B-rating and may be subject to change in the future. Unit 3 is a base-loaded boiler. It's load range varies from the low end (plant reliability—ready to respond in the event of a malfunction in Unit 4 or Unit 5), medium loads (increased customer steam loads) to high loads (i.e., during Unit 4 or Unit 5 overhauls). The load range varies within the month, and has patterns throughout the year. Therefore, the Division believes that a baseline period of 2000 – 2008 is warranted for CENC Boiler 3 due to the factors listed above. The baseline emissions for Boiler 3 are further detailed in Table 4

**Table 4: CENC Unit 3 Detailed Baseline Emissions**

| Pollutant | Unit 3 (2000 – 2008) | |
|---|---|---|
| | Annual Emissions* (tpy) | Annual Emissions** (lb/MMBtu) |
| $NO_x$ | 205 | 0.21 |
| $SO_2$ | 257 | 0.26 |
| $PM_{10}$ | 2 | 0.037*** |

*Using most recent three calendar years (Division APEN data).

**The Division calculated annual average rate (lb/MMBtu) from the most recent three calendar years, the maximum heat input and annual operating hours.

***The $PM_{10}$ emission rate is determined from the last Title V permit compliance stack test (August 24, 2007).

## III. Units Evaluated for Control

As documented by CENC, this boiler fires low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 5.

**Table 5: Coal Specifications (2006 – 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| B003 | 12,541 | 0.42 | 8.38 |

Table 1 lists the units at Colorado Energy Nations Golden Facility that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

**Table 6: Uncontrolled emission factors for CENC Boilers**

| Emission Unit | Pollutant | Fuel |
|---|---|---|
| | | Coal (bituminous) (lb/ton) |
| Boiler 3[2] | $NO_x$ | 11 |
| | $SO_2$ | 38 x %S = 16.0* |
| | $PM/PM_{10}$ | PM – 66<br>$PM_{10}$ – 13.2 |

*%S = % of sulfur present in coal supply. For example, 38 x 0.42 = 16.0
**%A = % of ash present in coal supply. For example, 10 x 8.39 = 83.9

It is worth noting that although Boiler 3 was on-line the majority of the time, it ran at reduced capacity due to production requirements, demonstrated in Table 7.

**Table 7: Boiler 3 Baseline Capacity Factor**

| Heat Input (HI) (MMBtu/year) | | |
|---|---|---|
| Potential HI | 1,971,000 | B3 % Potential-HI |
| 2006 | 874,569 | 44.37% |
| 2007 | 711,157 | 36.08% |
| 2008 | 805,320 | 40.86% |
| Average | 797,015 | 40.44% |

## IV. Reasonable Progress Evaluation of Boiler 3

### *a. Sulfur Dioxide*

### Step 1: Identify All Available Technologies

CENC identified five $SO_2$ control options:

Flue gas desulfurization (FGD):

Lime or limestone-based (wet FGD)

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.
http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Lime spray dry absorber (SDA or dry FGD)
Dry sorbent injection – Trona (DSI)
Fuel switching – different coal type
Fuel switching – natural gas

**Step 2: Eliminate Technically Infeasible Options**

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

*Dry FGD:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling $SO_2$ Emissions: A Review of Technologies[4] evaluates various $SO_2$ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

bound the facility to the north and east. Table 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with $SO_2$, the design gas residence time in a SDA is approximately 10 seconds. For Boiler 3, a SDA vessel for each boiler, not including other associated equipment, would be approximately 27 feet in diameter by 47 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on Boiler 3.

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential $SO_2$ controls on Units 4 and 5. It can be reasonably assumed that this visit also applies to Unit 3. The Division noted:

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.




**Figure 2: Aerial Zoom of CENC Facility**

***DSI:*** Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the $SO_2$ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, $NO_x$ to $SO_2$ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum $SO_2$ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum $SO_2$ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% $SO_2$ removal. In practical application, a higher $SO_2$ removal rate may be possible, while it is also possible that a lower $SO_2$ removal rate may be necessary to limit the brown plume formation. This determination would require actual $SO_2$ removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boiler 3.

*Fuel Switching – Different Coal Type*: CENC asserts that the facility already utilizes low sulfur, high heating value bituminous coal from western Colorado. Typically, the coal contains only about 0.43 percent sulfur with a heating value of 12,100 Btu/lb and potential $SO_2$ emissions of 0.73 lb/MMBtu. The sulfur content of CENC's Colorado coal rivals the low sulfur properties of Powder River Basin (PRB) coal from Wyoming, and therefore, it represents the lowest sulfur coal available. Any shift from the purchase of local Colorado coal would have an adverse effect on Colorado mining and transportation industries.

Additionally, CENC notes that PRB coal is extremely dusty to handle, being much more friable than the Colorado coal presently used) and it generates dust through weathering much more quickly than bituminous coal. PRB coal also is subject to spontaneous combustion in and around material handling systems and silos. The generation of fugitive dust and periodic spontaneous combustion is a tremendous issue at a site such as a Coors Brewery, which precludes conversion to PRB coal. Therefore, a change in coal supply is not a feasible RP control option.

*Fuel Switching – Natural gas*: Natural gas offers some operating and maintenance advantages. The use of natural gas would eliminate coal handling and baghouse operating and maintenance labor as well as ash handling and disposal. Natural gas fuel switching is a feasible option for CENC Boiler 3.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

CENC provided the Division annual average control estimates. In the Division's experience, 30-day $SO_2$ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boiler 3 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers.

*DSI:* CENC asserts that the maximum $SO_2$ removal rate that can be achieved to be 65% $SO_2$ removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals[5] and to be conservative since this technology is relatively novel.

*Fuel Switching – Natural Gas:* Conversion from coal to natural gas would reduce $SO_2$ emissions by almost 100% from each unit using EPA's AP-42 emission factors[6] and concurs with CENC's submittal.

Table 8 summarizes each available technology options and technical feasibility for $SO_2$ control on CENC Boiler 3.

**Table 8: CENC Boiler 3 SO2 Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Wet FGD | 52-98%, median 90%[7] | Y |
| Dry FGD | 70 – 90% (CENC) | N |
| DSI (Trona) | ≤65% (CENC) | Y |
| Fuel switching – different coal type | minimal (CENC) | N |
| Fuel switching – natural gas | 99% (EPA AP-42) | Y |

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

CENC submitted cost estimates for DSI and natural gas fuel switching for Boiler 3 on May 7, 2010.

*Wet FGD*: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.

[5] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

[6] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[7] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

*DSI:* PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. . DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of $SO_2$ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of $SO_2$ collected. Detailed capital and annual cost data are presented in "CENC RP APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI.

**Table 9: DSI Cost Comparisons**

| Facility & Unit | Size (MW) | Annualized Costs ($/year) | Cost Effectiveness ($/ton) | Ratio ($/kW) |
|---|---|---|---|---|
| Colorado Energy Nations – Boiler 3 | 24 | $1,340,661 | $9,114 | $55.86 |
| Colorado Energy Nations – Boiler 4 | 35 | $1,766,000 | $3,774 | $50.46 |
| Colorado Springs Utilities – Drake Unit 5 | 51 | $1,746,172 | $2,293 | $34.33 |
| Colorado Energy Nations – Boiler 5 | 65 | $2,094,000 | $2,485 | $32.22 |
| Colorado Springs Utilities – Drake Unit 6 | 85 | $2,910,287 | $1,741 | $34.24 |

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[8] CENC Boiler 3 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

*Fuel Switching – Natural Gas:* The Division used EPA's Cost Control Manual[9] to estimate annual operating costs, of approximately $25,000 per ton of $SO_2$

[8] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.
[9] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

removed annually for Boiler 3 at the CENC facility.[10] However, it should be noted that natural gas prices vary significantly; the Division used 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[11] to determine natural gas costs. Therefore, the Division concurs that the natural gas estimates submitted by CENC on May 7, 2010 to be reasonable.

In the February 8, 2010 submittal, CENC notes that the fuel is the largest steam production cost incurred by CENC, and stresses the variability in natural gas prices. CENC also emphasized the added negative Colorado economic impact in that CENC coal is purchased from Colorado mines, which may be offset by the natural gas purchases also from Colorado-based corporations. The use of natural gas would eliminate pulverizer and baghouse operating and maintenance costs as well as ash handling and disposal costs. Other boiler maintenance costs would be reduced if coal was not burned.

**Table 10: CENC Unit 3 Resultant SO2 Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 257 | 0.260 | 0.273 |
| DSI - Trona | 60 | 103 | 0.104 | 0.109 |
| Fuel Switching - Natural Gas | 100 | 0 | 0.000 | 0.000 |

**Table 11: CENC Unit 3 SO2 Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| DSI - Trona | 154 | $1,340,661 | $8,709 | $57 |
| Fuel Switching - Natural Gas | 257 | $1,428,911 | $5,569 | -$31 |

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control

[10] Colorado Air Pollution Control Division Technical Analysis – CENC RP APCD Technical Analysis, 2010.

[11] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

*Traditional Wet FGD:* Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP $SO_2$ control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of $SO_2$ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in $SO_2$ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental $SO_2$ emission reduction benefits (tons of $SO_2$ reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when applied to this small boiler at the CENC facility (Boiler 3).

*DSI:* CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,[12] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

*Fuel Switching – Natural Gas:* Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.08 Δdv for DSI applied to Boiler 4 (360 MMBtu/hr). DSI controls for Boiler 4 would reduce $SO_2$ emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce $SO_2$ emissions by about 147 tons per year. Fuel switching to natural gas would reduce $SO_2$ emissions by an estimated 245 tons annually. Consequently, it is reasonable to infer, based on scaling, that either control applied to Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

[12] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

**Table 12: CENC Boiler 4 $SO_2$ Modeling Results**

| $SO_2$ Control Method | | CENC - Boiler 4 | |
|---|---|---|---|
| | Emission Reduction (tpy) | $SO_2$ Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | --- | 0.90 | --- |
| DSI - Trona | 268 | 0.26 | 0.08 |

Determination

Table 13 illustrates fuel analysis from 2000 – 2010. The Division believes a 20% contingency factor is warranted for CENC Boiler 3 due to the factors listed on page 5. Based on Table 13, the maximum SO2 emissions from the past decade (2000 – 2010) is 0.99 lb/MMBtu. With the uncertainty factor, the Division believes that a 1.2 lb/MMBtu is appropriate for RP.

**Table 13: CENC Boiler 3 Coal Supply SO2 Limit Support**

| | 2000-2006 | 2006-2008 | 2009-2010 |
|---|---|---|---|
| Minimum Btu/lb | 11,068 | 11,221 | 11,444 |
| Maximum % Sulfur | 0.55 | 0.55 | 0.57 |
| *Theoretical lb/MMBtu…* | | | |
| Maximum B3 Conversion Sulfur to SO2 (using fuel analysis) | 0.99 | 0.98 | 0.99 |

Based upon its consideration of the five factors summarized herein, the state has determined that $SO_2$ RP is the following SO2 emission rate:

CENC Boiler 3: 1.2 lb/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

***b. Filterable Particulate Matter (PM and $PM_{10}$)***

CENC Boiler 3 is equipped with fabric filter baghouses to control PM/$PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Condition 2.2 requires Boiler 3 to comply with State Regulation No. 1 where the $PM/PM_{10}$ emission limit is calculated from the equation $PE = 0.5(FI)^{-0.26}$, where PE= Particulate Emissions in lbs/MMBtu and FI = Fuel input in million Btu per hour. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 14 shows the most recent stack test data (August 24, 2007). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >90% control.

**Table 14: CENC 2007 Stack Test Results**

| Pollutant | Boiler 3 (lb/MMBtu) |
|---|---|
| Filterable $PM_{10}$ | 0.037 |
| $PM_{10}$ Control efficiency | 93.0% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

This boiler is subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[13] As currently proposed, the boiler will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[14]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of

[13] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

[14] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible (less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The state has determined that an emissions limits of 0.07 lb/MMBtu (PM/PM10 represents the most stringent control option. The unit is exceeding a PM control efficiency of 90%, and the control technology and emission limit is RP for PM/$PM_{10}$. The state assumes that the RP emission limit can be achieved through the operation of the existing fabric filter baghouse.

***c. Nitrogen Oxides ($NO_x$)***

**Step 1: Identify All Available Technologies**

CENC, using a similar unit's $NO_x$ analysis[15], identified eight potential $NO_x$ control options:

Flue Gas Recirculation (FGR)
Low-temperature Oxidation System (LoTOx)
Selective Non-Catalytic reduction (SNCR)
Rotating Over-Fire Air w/ Rotamix (ROFA)
Fuel switching – different fuel type (natural gas)
Regenerative Selective Catalytic Reduction (RSCR)
High Temperature Selective Catalytic Reduction (HT SCR)
Low Temperature Selective Catalytic Reduction (LT SCR)

The Division also identified and examined the following additional control option for this unit:

Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

**Step 2: Eliminate Technically Infeasible Options**

*Flue Gas Recirculation (FGR):* FGR technology extracts up to 20 to 30% of the flue gas from downstream of the economizer, air heater, or particulate control equipment, and is mixed into the combustion inlet air duct. The amount of FGR

[15] "Black Hills Clark Station $NO_x$ Reduction Feasibility Study" BH Clark Station Unit 1. Prepared by CH2MHill. December 2009.

that is achievable is determined by a boiler's operating characteristics and the ability to mix with primary air to allow for good fuel bed combustion stability. Flue gas recirculation is considered technically feasible for CENC Boiler 3.

*LoTOx System:* The LoTox system has the potential of significant $NO_x$ reduction; however, the process requires operation in conjunction with a wet scrubber. CENC does not currently have a wet scrubber in service, has a limited footprint in which to locate a wet scrubber, and the Division has determined that wet scrubbers are not being considered for this facility due to non-air and energy impacts. Therefore, the LoTOx alternative is not considered due to the determination regarding wet scrubbers.

*SNCR:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boiler 3.

*ROFA:* Nalco Mobotec markets ROFA as an improved second generation OFA system. ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. Nalco Mobotec offers the ROFA system as a stand-alone installation, or with the Rotamix feature. Rotamix is Nalco Mobotec's version of SNCR technology, and ammonia is injected into the ROFA airstream. ROFA is considered technically feasible for CENC Boiler 3.

*Fuel switching – different fuel type (natural gas):* Natural gas reburning technology is a staged fuel approach using an expanded volume of the furnace to control $NO_x$ production, rather than only within the flame envelope, also referred to as Methane de-$NO_x$. The primary solid fuel combustion delivery and boiler location remains the same, and for the case of CENC Boiler 3 this is currently assumed to occur on the traveling fuel grate. The secondary fuel introduction point is after the primary fuel burn zone, in a fuel-rich reaction zone (the reburn zone). While other fuels may be used in the reburning zone, natural gas is most common and $NO_x$ reductions of 30-70% may be feasible. Higher removals are associated with longer boiler residence times. Therefore, 50% was used for the analysis due to the relatively short boiler at CENC (similar to Black Hills Clark Station Unit 1). Natural gas fuel switching is considered a technically feasible alternative for CENC Boiler 3.

*RSCR/HT SCR/LT SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

CENC estimated that a retrofit SCR system on Boiler 3 could achieve 0.024 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. CENC evaluated three types of SCR for this analysis – regenerative SCR, high-temperature SCR, and low-temperature SCR. These three different options were evaluated because of the potential variable inlet temperature on a spreader stoker boiler such as Unit 3. Regenerative SCR notably may not achieve the same reductions as the other two SCR options, but regardless was evaluated. All three SCR options – RSCR, HTSCR, and LTSCR – are considered technically feasible for CENC Boiler 3.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[16] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[17] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boiler 3.

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[18]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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[16] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

[17] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

[18] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[19] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boiler 3 to determine control efficiencies and annual reductions.

*Flue Gas Recirculation (FGR):* CENC estimated a 20% $NO_x$ reduction. Flue gas recirculation is considered an operational modification, since fuel is rearranged in the main combustion zone. EPA's AP-42 emission factor tables estimate operational modifications to reduce $NO_x$ 10 –20%.[20] It should be noted the baseline $NO_x$ emission rate (0.17 lb/MMBtu) is much lower than other spreader stoker boilers examined in many control case studies.[21] The Division considers this level of control optimistic and concurs with CENC's control efficiency estimates for FGR.

*SNCR:* CENC noted in the May 6, 2010 submittal that the similar unit was assumed to achieve 40% control for SNCR. However, CENC determined that 30% control was a more realistic estimate. EPA's SNCR Air Pollution Control Technology Fact Sheet states that SNCR achieves 30 – 50% control, which concurs with the Division's experience. The Division determined in CENC's BART analysis that an appropriate $NO_x$ reduction estimate is 30%; therefore, the Division concurs with CENC's control efficiency estimate.

*ROFA:* A recent AWMA study noted that ROFA achieves from 45 – 60% $NO_x$ reduction depending on temperature and distribution of combustion products. [22] CENC estimated a reduction of 57.1% based on a vendor guarantee for a similar unit. This results in a resultant $NO_x$ emission rate of 0.07 lb/MMBtu. In the Division's experience, this emission rate may not be realistically achievable and will require more study if applicable.

*Fuel switching – different fuel type (natural gas):* CENC estimates 50% $NO_x$ reduction by converting fuel to natural gas. This is equal to about 0.09 lb/MMBtu, which is consistent with EPA's AP-42 emission factor tables for a

[19] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[20] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[21] EPA, Office of Air and Radiation. "Alternative Control Technique Document – $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers." Emission Standards Division. http://www.epa.gov/ttncatc1/dir1/icboiler.pdf
[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

large wall-fired boiler controlled with flue gas recirculation (0.098 lb/MMBtu).[23] Therefore, the Division concurs with CENC's control efficiency estimate.

*RSCR/HT SCR/LT SCR:* CENC estimates 74.5% $NO_x$ control for RSCR and 85.7% for HTSCR and LTSCR. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[24,25] RSCR will not achieve the same control efficiencies as HTSCR and/or LTSCR due to the heat input being required through burner arrangement located between two canisters and can be applied to relatively cold flue gas temperatures seen after particulate control equipment. The Division notes that these control efficiencies, due to the low baseline $NO_x$ emission rate, result in extreme emission rates (0.02 – 0.04 lb/MMBtu) and may not be realistically achievable, but concurs with CENC's current estimate for purposes of this RP evaluation.

**Table 15: CENC Boiler 3 $NO_x$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners (LNB) | n/a | N – coal stoker boiler |
| Flue Gas Recirculation (FGR) | ~20% | Y |
| Selective non-catalytic reduction (SNCR) | ~30 - 50% | Y |
| Rotating Overfire Air (ROFA) | 45-60% | Y |
| Fuel switching – natural gas | ~50% | Y |
| Selective catalytic reduction options (RSCR, HTSCR, LTSCR) | ~75 – 90% | Y |
| ECO® | n/a | N |
| RRI | n/a | N |
| Coal reburn +SNCR | n/a | N |

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

*FGR:* The costs of flue gas recirculation for stoker boilers are not well documented. This type of modification is considered a pre-combustion boiler modification. This modification should be more cost-effective than other options,

[23] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf
[24] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[25] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

considering that either a new FGR fan will have to be installed or that the existing forced draft (FD) fan may be used to inject the flue gas into the combustion air. The Division considers the annualized cost of approximately $280,000 for FGR to be reasonable for this small boiler.

*SNCR:* The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of CENC Boiler 3.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] The CENC-estimated SNCR costs for operating expenses is about 77% for Boiler 3. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[27]

The Division calculates cost effectiveness (using CENC cost estimates) for SNCR on Boiler 3 to be about $10,150 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[28,29] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[30] CENC's estimates are greater than these ranges due to the small size of the boiler, the difficulty of the retrofit, and the different boiler configuration. There is a lack of information regarding the application of SNCR to spreader stoker boiler. Therefore, the Division concludes that CENC's cost estimates for SNCR are reasonable.

*ROFA:* The Division notes lack of information regarding ROFA cost estimates, especially applied to spreader stoker boilers. Therefore, the Division notes that CENC's estimated ROFA annualized costs are similar to SNCR, which is a

[26] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[27] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[28] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[29] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[30] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

comparable control technology in terms of achievable reductions and concludes that CENC's cost estimates for ROFA are reasonable.

*RSCR/HTSCR/LTSCR:* Using CENC estimates, the Division calculates that the three SCR options range from $15,650 - $22,300 per ton. Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[31,32] CENC's cost estimates are much higher than this range, but the small size of the boiler, the difficulty of the retrofit, and the boiler configuration, the Division concludes that CENC's cost estimates for SCR are reasonable.

**Table 16: CENC Boiler 3 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | | | |
|---|---|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) | Annual Average (lb/hour) | 30-day Rolling Average (lb/hour) |
| Baseline | --- | 180 | 0.25 | | 56 | 65 |
| Flue Gas Recirculation | 20.0 | 144 | 0.15 | 0.17 | 41 | 47 |
| SNCR | 30.0 | 144 | 0.13 | 0.15 | 33 | 38 |
| Fuel Switching - NG | 34.8 | 118 | 0.12 | 0.14 | 29 | 33 |
| ROFA w/ Rotamix | 57.1 | 77 | 0.08 | 0.09 | 18 | 20 |
| Regenerative SCR | 74.5 | 46 | 0.05 | 0.05 | 11 | 12 |
| High Temperature SCR | 85.7 | 26 | 0.03 | 0.03 | 6 | 7 |
| Low Temperature SCR | 85.7 | 26 | 0.03 | 0.03 | 6 | 7 |

[31] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[32] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

**Table 17: CENC Boiler 3 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Flue Gas Recirculation | 33.7 | $278,358 | $7,716 | $214 |
| SNCR | 50.6 | $513,197 | $9,484 | $98 |
| Fuel Switching - NG | 58.7 | $1,428,911 | $22,763 | $1,534 |
| ROFA w/ Rotamix | 96.3 | $978,065 | $9,496 | -$330 |
| Regenerative SCR | 125.6 | $1,965,929 | $14,629 | $164 |
| High Temperature SCR | 144.5 | $2,772,286 | $17,933 | $164 |
| Low Temperature SCR | 144.5 | $3,222,223 | $20,844 | --- |

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

*FGR:* Installation of a FGR system is not expected to impact the boiler efficiency or forced draft fan power usage significantly. Thus, this factor does not influence the selection of this control.

*Fuel Switching – Natural Gas:* Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

*ROFA w/ Rotamix:* The ROFA system requires installation and operation of the ROFA fans on this boiler, with a 125 hp fans being anticipated based on a similar boiler analysis. The Rota system alone will have a modest increase in power consumption. This system may result in higher levels of carbon in the fly ash due to incomplete combustion. Rotamix may impact any potential salability of fly ash due to ammonia levels. However, the Division is not currently aware of CENC selling fly ash.

*SNCR /SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to "CENC BART Submittals" for more information.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.12 Δdv for LNB+SOFA+SNCR applied to Boiler 4 (360 MMBtu/hr). LNB+SOFA+SNCR controls for Boiler 4 would reduce $NO_x$ emissions by approximately 368 tons per year. SCR controls for Boiler 3 would reduce $NO_x$ emissions by about 145 tons per year. Consequently, it is reasonable to infer that either control applied to

Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

**Table 18: CENC Boiler 4 $NO_x$ Modeling Results**

| NOx Control Method | | CENC - Boiler 4 | |
|---|---|---|---|
| | Emission Reduction (tpy) | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | --- | 0.67 | |
| LNB | 60 | 0.45 | 0.05 |
| SNCR | 180 | 0.35 | 0.07 |
| LNB + SOFA | 210 | 0.32 | 0.08 |
| LNB + SOFA + SNCR | 368 | 0.19 | 0.12 |

Determination

Based on review of historical actual load characteristics of this boiler, the Division proposes an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor (similar to $SO_2$) due to the reasons listed on page 5.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan, and thus not reasonable.

V. Reasonable Progress Evaluation of Boiler 4 and Boiler 5

Boiler 4 and Boiler 5 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Boilers 4 and 5 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available $NO_x$, $SO_2$, and $PM/PM_{10}$ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for $NO_x$, $SO_2$, or $PM/PM_{10}$ for Boiler 4 and Boiler 5 at the CENC facility.

# COMBUSTION TURBINE POINT SOURCE CATEGORY 4-FACTOR ANALYSIS

## I. Source Description

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the State's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

Control strategies for this source category are:
NOx – Steam or water injection, advanced dry low NOx combustion system, and selective catalytic reduction (SCR)

Cumulatively, this emissions source category is projected to be a minimal single category of Colorado point sources with a total of 56 turbines. Of this total, turbines located as single sources at Reasonable Progress facilities are 18. Total state-wide $NO_x$ emissions (2007 inventory) are approximately 284,037 tons/year. This source category is about 0.7% of total statewide emissions; therefore, the Division considers this source category to be nominal. Regardless, the Division evaluated all combustion turbines, regardless of fuel type, at Reasonable Progress facilities. The majority of combustion turbines (assumed 17 out of 18 based on inventory limitations) are natural-gas fired.

## II. Source Emissions

| Pollutant | Total 2006 – 2008 Averaged Annual Emissions (tpy) | Total RP Turbine 2006 – 2008 Averaged Annual Emissions (tpy) | RP Turbine Emissions compared to total state-wide turbine emissions (%) |
|---|---|---|---|
| $NO_2$ | 2,003 | 473 | 24% |

The Division analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are 5 Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe

Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two emit over federal significance levels as depicted below.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of $NO_x$ equal to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for $SO_2$, $NO_x$ and $PM_{10}$ to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines "emissions unit" as "any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV (acid deposition control) of the federal act, or of the term "source" for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [1] ." These *de minimis* levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

| Facility – Turbine | Total 2006 – 2008 Averaged NOx Annual Emissions (tpy) | Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy) | Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy) | Greater than *de minimis* levels? |
|---|---|---|---|---|
| Valmont – Turbine #6 | 12.6 | 0.4 | 0.1 | No |
| Valmont – Turbine #7 | 27.4 | 0.2 | 2.8 | No |
| Valmont – Turbine #8 | 1.5 | 0.0 | 0.1 | No |
| Arapahoe – Turbine #5 | 25.5 | 0.4 | 5.0 | No |
| Arapahoe – Turbine #6 | 15.3 | 0.4 | 5.0 | No |
| Arapahoe – Turbine | 4.1 | 0.2 | 3.7 | No |
| Nixon – Turbine #2 | 0.7 | 0.0 | 0.2 | No |
| Nixon – Turbine #3 | 1.2 | 0.0 | 0.3 | No |
| Nixon – Front Range Power | 159.6 | 2.9 | 4.9 | Yes – NOx only |

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

| | | | | |
|---|---|---|---|---|
| Plant – Turbine #1 | | | | |
| Nixon – Front Range Power Plant – Turbine #2 | 147.9 | 2.8 | 4.9 | Yes – NOx only |
| Rawhide Turbine A | 2.5 | 0.1 | 0.5 | No |
| Rawhide Turbine B | 4.0 | 0.1 | 0.8 | No |
| Rawhide Turbine C | 2.7 | 0.1 | 0.5 | No |
| Rawhide Turbine D | 2.9 | 0.1 | 0.5 | No |
| Pawnee – Turbine #1 | 25.4 | 0.3 | 3.3 | No |
| Pawnee – Turbine #2 | 25.0 | 0.2 | 2.7 | No |

Therefore, for the purposes of this RP planning period, the Division will evaluate the Nixon – Front Range Power Plant – Turbines #1 and #2 as they are the two combustion turbines emitting over *de minimis* levels.

## III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Four technologies have been identified to lower emissions from combustion turbines:

1. Wet controls using steam or water injection to reduce combustion temperatures for NOx control

2. Dry controls using advanced combustor design to suppress NOx formation and/or promote CO burnout

3. Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

**Technology #2:** This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th Edition, Volume 1, Chapter 1, Section 3.1.4.1: "Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one."

**Technology #3:** This technology was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th

Edition, Volume 1, Chapter 1, Section 3.1.4.2: "Since thermal NOX is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NOx emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NOX formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NOx generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NOx formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx."

**Technology #4**: This technology (adding SNCR or SCR) involves adding control equipment and reagent to treat turbine exhaust.

Step 2: Eliminate Technically Infeasible Options

**Technology #1:** This technology is technically feasible.

**Technology #2:** This technology is technically feasible.

**Technology #3:** This technology is technically feasible and is already installed at the Nixon – Front Range Power Plant combustion turbines.

**Technology #4:** This technology is technically feasible, although a Division of the EPA's RBLC database revealed SCR is the predominant post-combustion control technology for combustion turbines and did not find any examples of SNCR post-combustion technology applied to combustion turbines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

**Technology #1:** Since this control technology is specific fuel type usage, control efficiency are not applicable.

**Technology #2:** EPA's AP-42 factor database cites this technology as achieving control efficiencies of 60% or greater. However, this technology will not be evaluated in this analysis further since the dry low-NOx combustion systems already installed on the turbines at the Front Range Power Plant achieve greater than 85% control, which is greater than the 60% estimate achievable by wet controls.

**Technology #3:** The Division calculated that the controlled-uncontrolled ratio for advanced dry-low NOx combustions using EPA's AP-42 emission factors is approximately 70% and may be greater in site-specific cases. The combustion turbines at the Nixon – Front Range Power Plant were installed with these systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions (calculated using the 2006 – 2008 RP baseline period), respectively.

**Technology #4:** EPA's AP-42 emission factor description indicates that a SCR in good working order can achieve removal efficiencies ranging from 65 – 90 percent from the NOx exhaust stream. AP-42 is silent on control efficiencies regarding SNCR. During a research review, the Division could not find any instances of a commercial-scale SNCR applied at a natural-gas fired combustion turbine. Therefore, SNCR will not be considered further in this analysis.

Step 4: Evaluate Impacts and Document Results

The Division reasons that SCR requires significant capital expenditures and will result in minimal additional NOx reductions, if any. Regardless, the Division analyzed additional achievable NOx reductions if SCR was installed at these two turbines. Applying SCR at 90% to both turbines would result in about 275 additional tons of NOx reduced annually. Using another Colorado SCR analysis from the same utility (Colorado Springs Utilities), the Division estimates that annualized costs for installing SCR to both turbines will be approximately $8 million each, resulting in about $57,000 - $62,000 per ton of NOx reduced annually.

The time necessary for compliance will depend on the type of control implemented. Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the SCR control option. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

There are no energy or non-air quality impacts for fuel usage of pipeline quality natural gas or for advanced dry low-NOx combustion systems. The energy and non-air quality impacts of SCR and SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Step 5: Select Reasonable Progress Control

The Division determines that any potential reductions from this source category are minimal, if any. Pipeline quality natural gas is inherently clean for SO2 and PM10. For NOx, the majority of combustion turbines already apply advanced dry-low NOx combustion systems, especially the larger turbines.

Based on its consideration of the four factors summarized herein, the state has determined that NOx RP for combustion turbines is existing controls and emission limits. Though other controls achieve better emission reductions, the expense of these options coupled with predicted minimal visibility improvement were determined to be excessive.

**Reasonable Progress Analysis of Control Options**
**For**
**Tri-State Generation & Transmission Association, Inc. – Craig Station Unit 3**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Tri-State Generation & Transmission Association, Inc. |
| Source Type: | Electric Utility Steam Generating Unit |
| SCC (EGU): | 10100202 |
| Boiler Type: | Three Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2) and one front-fired (Unit 3) |

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Unit 3, rated at 4,600 MMBtu/hour (net 408 MW) was placed in service in 1984.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide ($SO_2$) emissions. The boilers are equipped with ultra-low nitrogen oxide ($NO_x$) dual register burners with overfire air for minimization of $NO_x$ emissions. The FGD and ultra low $NO_x$ burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of $SO_2$ and low-$NO_x$ burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for $NO_x$ limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area.

For this analysis, the Division also relied on the existing Construction permit, historical information regarding Craig Station, and information about similar facilities to determine RP for $NO_x$, $SO_2$, and $PM_{10}$. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same. Units 1 and 2 are considered BART-eligible, being industrial boilers

with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010. **Error! Reference source not found.** depicts technical information for Unit 3 at Craig Station.

**Table 1: Craig Unit 3 Technical Information**

| | Unit 3 |
|---|---|
| Placed in Service | 1984 |
| Gross Boiler Rating, MMBtu/Hr for coal | 4,600 |
| Electrical Power Rating, Net Megawatts | 408 |
| Description | Babcock & Wilcox coal, dry bottom boiler - Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization |
| Air Pollution Control Equipment | $PM/PM_{10}$ – Pulse Jet Fabric Filter Baghouse (1984 – upgraded between 2007 and 2009)<br>$NO_x$ – Low $NO_x$ Burners with Over-Fire Air (upgraded between 2007 and 2009)<br>$SO_2$ – Dry Limestone FGD (1984 – upgraded between 2007 and 2009)<br>Existing turbine generator replaced with larger unit completed in May 2009. |
| Emissions Reduction (%)* | $NO_x$ – 19.0%/38.8%*<br>$SO_2$ – 80.9% |

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

| | |
|---|---|
| | PM – 99.8%<br>$PM_{10}$ – 99.6% |

*Emissions Reduction estimated by comparing pre-control upgrade 2006-2008 CAMD data to AP-42 emission factor data. The first $NO_x$ number compares the additional reduction achieved by the ultra-low $NO_x$ burners vs. the original low-$NO_x$ burners and the second $NO_x$ number compares uncontrolled AP-42 factor to actual average emission factor (June 2009 – June 2010). For PM/$PM_{10}$., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

## II. Source Emissions

Table 2 summarizes the $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

**Table 2. Summary of 2006 - 2008 Averaged Emissions – Craig Station**

| $NO_x$ (tons/year) | $SO_2$ (tons/year) | $PM_{10}$ (tons/year) |
|---|---|---|
| 16,942 | 3,769 | 363 |

**Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Craig Station**

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| Unit 1 | $SO_2$ (tons) | 865.1 | 1053.0 | 990.5 | 969.5 |
| | $SO_2$ (lb/ MMBtu) | 0.06 | 0.06 | 0.06 | 0.06 |
| | $NO_x$ (tons) | 4665.7 | 5817.3 | 5056.9 | 5180.0 |
| | $NO_x$ (lb/ MMBtu) | 0.34 | 0.32 | 0.30 | 0.32 |
| | PM (tons) | 92.9 | 107.3 | 101.1 | 100.4 |
| | PM (lb/ MMBtu) | 0.007 | 0.006 | 0.006 | 0.006 |
| Unit 2 | $SO_2$ (tons) | 999.6 | 797.1 | 1149.1 | 981.9 |
| | $SO_2$ (lb/ MMBtu) | 0.05 | 0.05 | 0.06 | 0.06 |
| | $NO_x$ (tons) | 5548.7 | 4965.7 | 5566.4 | 5360.3 |
| | $NO_x$ (lb/ MMBtu) | 0.30 | 0.32 | 0.30 | 0.31 |
| | PM (tons) | 90.7 | 81.9 | 87.5 | 86.7 |
| | PM (lb/ MMBtu) | 0.005 | 0.005 | 0.005 | 0.005 |
| Unit 3 | $SO_2$ (tons) | 1721.3 | 1948.5 | 1782.6 | 1817.5 |
| | $SO_2$ (lb/ MMBtu) | 0.10 | 0.11 | 0.11 | 0.10 |
| | $NO_x$ (tons) | 6592.1 | 6670.1 | 5943.9 | 6402.0 |
| | $NO_x$ (lb/ MMBtu) | 0.38 | 0.36 | 0.35 | 0.37 |
| | PM (tons) | 70.4 | 71.8 | 67.7 | 70.0 |
| | PM (lb/ MMBtu) | 0.004 | 0.004 | 0.004 | 0.004 |
| *Auxiliary Boiler (130 MMBtu/hr) Fuel Oil Boiler* | *$SO_2$ (tons)* | *0* | *0* | *0* | *0* |
| | *$SO_2$ (lb/ MMBtu)* | *0* | *0* | *0* | *0* |
| | *$NO_x$ (tons)* | *0* | *0* | *0* | *0* |

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| | *$NO_x$ (lb/ MMBtu)* | *0* | *0* | *0* | *0* |
| | *PM (tons)* | *0* | *0* | *0* | *0* |
| | *PM (lb/ MMBtu)* | *0* | *0* | *0* | *0* |
| *F101a – Coal Hauling – Units 1 & 2* | *PM (tons)* | *8.15* | *8.15* | *11.39* | *9.23* |
| *F101b – Coal Unloading to Grizzly – Units 1 & 2* | *PM (tons)* | *0.04* | *0.04* | *0.05* | *0.04* |
| *F101c – Coal Surge Pile* | *PM (tons)* | *0.05* | *0.05* | *0.05* | *0.05* |
| *S101d – Primary Coal Crushing – Units 1 & 2* | *PM (tons)* | *0.18* | *0.18* | *0.23* | *0.20* |
| *S101e – Secondary Coal Crushing Bldg – Units 1 & 2* | *PM (tons)* | *0.46* | *0.46* | *0.56* | *0.49* |
| *S101f – Common Coal Transfer Bldg Belt A* | *PM (tons)* | *0.001* | *0.001* | *0.0013* | *0.0011* |
| *S101g – Common Coal Transfer Bldg Belt B* | *PM (tons)* | *0.001* | *0.001* | *0.0013* | *0.0011* |
| *S101h – Coal Stackout Building – Units 1 & 2* | *PM (tons)* | *0.002* | *0.002* | *0.0025* | *0.0022* |
| *S101i - Coal Stackout – Units 1 & 2* | *PM (tons)* | *0.051* | *0.051* | *0.063* | *0.055* |
| *F101 j -Coal Storage Piles – Units 1 & 2* | *PM (tons)* | *0.63* | *0.63* | *0.63* | *0.63* |
| *S101k – Coal Reclaim A – Units 1 & 2* | *PM (tons)* | *0.0018* | *0.0018* | *0.0019* | *0.0018* |
| *S101l – Coal Reclaim B – Units 1 & 2* | *PM (tons)* | *0.0018* | *0.0018* | *0.0019* | *0.0018* |
| *S101m – coal Tripper Deck & Silos – Units 1 & 2* | *PM (tons)* | *0.0036* | *0.0036* | *0.0038* | *0.0037* |
| *S101n – Common Coal Drive House* | *PM (tons)* | *0.0036* | *0.0036* | *0.0038* | *0.0037* |
| *S203a – Fly Ash Storage Silo A – Units 1 & 2* | *PM (tons)* | *0.0047* | *0.0047* | *0.002* | *0.0038* |
| *S203b – Fly Ash Storage Silo B – Units 1 & 2* | *PM (tons)* | *0.0047* | *0.0047* | *0.002* | *0.0038* |
| *F203c – Fly Ash Truck Loading – Units 1 & 2* | *PM (tons)* | *0.0079* | *0.0079* | *0.0034* | *0.0064* |
| P204 – Ash Hauling & Storage – Unit 3 | PM (tons) | 62.2 | 62.2 | 62.2 | 62.2 |
| P201 – Limestone Hauling | PM (tons) | 14.7 | 14.7 | 17.5 | 15.6 |
| *F102a – Coal Train Unloading – Unit 3* | *PM (tons)* | *0.0607* | *0.0607* | *0.0676* | *0.063* |
| *S102b/c – Coal Conveyor Portal Building – Unit 3* | *PM (tons)* | *0.003* | *0.003* | *0.0034* | *0.0031* |
| *S102d – Secondary Coal Crushing (2 crushers0 – Unit 3* | *PM (tons)* | *0.68* | *0.68* | *0.76* | *0.71* |
| *S102e – Coal Stackout Building – Unit 3* | *PM (tons)* | *0.003* | *0.003* | *0.0034* | *0.0031* |
| *F102f – Coal Stackout – Unit 3* | *PM (tons)* | *0.076* | *0.076* | *0.085* | *0.078* |

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| *F102g – Coal Storage Pile – Unit 3* | *PM (tons)* | *0.24* | *0.24* | *0.24* | *0.24* |
| *S102h – Coal Reclaim System – Unit 3* | *PM (tons)* | *0.003* | *0.003* | *0.0034* | *0.0031* |
| *S102k – Common Coal Transfer Building Extension* | *PM (tons)* | *0.003* | *0.003* | *0.0034* | *0.0031* |
| *S102n – Common Coal Drive House* | *PM (tons)* | *0.003* | *0.003* | *0.0034* | *0.0031* |
| *S102i – Coal Tripper Deck and Silos – Unit 3* | *PM (tons)* | *0.0018* | *0.0018* | *0.0018* | *0.0018* |
| *S102j – Loadout Coal to Railcars – Unit 3* | *PM (tons)* | *0* | *0* | *0* | *0* |
| *F205a – Ash Hauling to "Landfill" (Outage Waste to Trapper)* | *PM (tons)* | *0.114* | *0.114* | *0.114* | *0.114* |
| *F205b – Ash and Wet Waste Hauling to/from Decant Basin* | *PM (tons)* | *0.676* | *0.676* | *0.676* | *0.676* |
| *F205c – Ash Unloading at "Landfill" (Outage Waste) & Ash Unloading at Decant Basin* | *PM (tons)* | *0.0024* | *0.0024* | *0.0024* | *0.0024* |
| *F205d – Wet Waste Unloading at Decant Basin* | *PM (tons)* | *0* | *0* | *0* | *0* |
| *F202a – Lime Hauling (trucks)* | *PM (tons)* | *0* | *0* | *0* | *0* |
| *S202b – Lime Unloading – Unit 3* | *PM (tons)* | *0.0011* | *0.0011* | *0.0012* | *0.0011* |
| *S202c – Lime Conveying & Silo – Unit 3* | *PM (tons)* | *0.0011* | *0.0011* | *0.0012* | *0.0011* |
| *S202d – Lime Day Bin* | *PM (tons)* | *0.0011* | *0.0011* | *0.0012* | *0.0011* |
| *S401/2 – Cooling Towers – Units 1 & 2* | *PM (tons)* | *10.3* | *10.3* | *10.3* | *10.3* |
| *Auxiliary Boiler* | *PM (tons)* | *0* | *0* | *0* | *0* |
| *S403 - Cooling Tower – Unit 3* | *PM (tons)* | *5.8* | *5.2* | *5.2* | *5.4* |

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day $NO_x$ rolling averages for the boilers are estimated to be 5-15% higher than the annual average emission rate.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Tri-State estimated that a realistic depiction of anticipated annual emissions for Unit 3, or "Baseline" Emissions", to be conservative, was the average of 30-day averages from 2009, or 0.33 lb/MMBtu for $NO_x$. Tri-State noted that this baseline reflects the recent PSD permit limit of 6,752 tons associated with a 2009 turbine upgrade. This baseline reflects the low-$NO_x$ burners and overfire air installed at Craig 3 in 2009. The Division notes that the 2006 – 2008 baseline period used for other RP and BART sources is not reasonable for Craig Unit 3 due to the recent upgrades. The Division also used the recent PSD permit limit of 6,752 tons for $NO_x$ and 2,125 tons for $SO_2$ to determine a baseline.

The notable difference is that the Division used the average capacity factor (based on heat input) from 2006 – 2008 to determine the baseline emissions, resulting in 0.28 lb/MMBtu for $NO_x$ and 0.09 lb/MMBtu for $SO_2$. Craig Unit 3 ran at an average of 86.4% capacity (based on heat input) from 2006 – 2008, thus this factor is assumed to be a reasonable baseline for this planning period. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 4.

**Table 4: Tri-State Craig Unit 3 Baseline Emissions**

| Pollutant | Unit 3 | |
|---|---|---|
| | Annual Emissions* (tpy) | Average Emissions (lb/MMBtu) |
| $NO_x$ | 5,693 | 0.283 |
| $SO_2$ | 1,792 | 0.089 |
| $PM_{10}$ | 148** | 0.007** |

*The Division calculated annual (tpy and lb/MMBtu) $NO_x$ and $SO_2$ emissions using 2006 – 2008 capacity factor and current PSD permit limits.
**The $PM_{10}$ emissions and emissions factor are from August 2009 stack test data; $PM_{10}$ current construction permit annual emission limit is 403 tons/year and 0.012 lb/MMBtu.

## III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. The Trapper contract expires in 2014. Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of $NO_x$-forming characteristics, Craig 3 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 3 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing $NO_x$ formation. The specifications for these coals are listed below in Table 6. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals. The actual APEN coal specifications (2006 – 2008) are listed below in Table 5.

**Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| Craig Unit 3 | 10,224 | 0.39 | 6.47 |

**Table 6: Craig Station Coal Specifications (2008)**

| Coal Mine/Region | Colowyo | Trapper | Twentymile |
|---|---|---|---|
| Coal Rank Classification | Sub-bituminous, Class A | Sub-bituminous, Class A | Bituminous |
| $H_2O$ (Moisture %) | 17.42 | 16.7 | 9.62 |
| Ash (%) | 5.71 | 6.5 | 11.93 |
| Sulfur (%) | 0.37 | 0.44 | 0.52 |
| Nitrogen (%) | 1.35 | ~1.5 | 1.57 |

| | | | |
|---|---|---|---|
| Heating Value (HHV Btu/lb) | 10,392 | 9,800 | 11,084 |

Uncontrolled emission factors are outlined in Table 7. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

**Table 7: Uncontrolled emission factors for Craig BART-eligible sources[2]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Unit 3 | 12 | 14.7 | 64.7 | 14.9 |

*$SO_2$ and $PM/PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

## IV. Reasonable Progress Evaluation of Unit 3

### A. Sulfur Dioxide ($SO_2$)

### Step 1: Identify All Available Technologies

The Division requested that Tri-State evaluate the option below, and received relevant information for this request on June 4, 2010:

***Dry FGD upgrades***

As discussed in EPA's BART Guidelines[3], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system

The current PSD permit $SO_2$ limits are depicted in Table 8.

**Table 8: Craig Unit 3 $SO_2$ PSD Permit Limits**

| | $SO_2$ limits (lb/MMBtu) Calendar day average | Reduction (%) Required 30-day rolling | Annual Emission Limit (tons/year) |
|---|---|---|---|
| Unit 3 | 0.20* | 80 | 2,125 |

*May be exceeded once during any calendar month.

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[3] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

**Step 2: Eliminate Technically Infeasible Options**

***Dry Flue Gas Desulfurization (FGD) Upgrades:*** Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power plants[4]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures $SO_2$ by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and then collected in a particulate control device.

Craig Unit 3 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for $SO_2$ removal from the gaseous emission stream of a utility boiler. Tri-State has since upgraded this system (between 2007 and 2009) and currently achieves greater than 80% $SO_2$ removal, with an actual annual average of approximately 0.09 lb/MMBtu. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[5]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to "Division RBLC Analysis" for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of $SO_2$ emissions found that lime spray drying processes have a median design efficiency of 90%[6] .

The BART Guidelines note potential upgrades for dry scrubbing systems[7]. These upgrades include:

-*Use of performance additives*
-*Use of more reactive sorbent*
-*Increase the pulverization level of sorbent*
-*Engineering redesign of atomizer or slurry injection system*

Tri-State examined BART-guideline dry scrubbing potential upgrades, with the following results:

-*Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of $SO_2$ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

[4] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[5] Colorado Operating Permit 96OPLR142 pg. 5 – $SO_2$ 30-day rolling average limit is 0.13 lb/MMBtu.
[6] EPA, 2000. "Controlling $SO_2$ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.
[7] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39171.

-*Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial peblle lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent.

-*Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Unit 3. However, the Division has evaluated the option of tightening the $SO_2$ emission limit for Craig Unit 3.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

The control effectiveness of tightening the 30-day rolling emission limit on Craig Unit 3 has been evaluated by the Division. The Division analyzed the period after Tri-State upgraded the turbine (post-control: June 2009 – June 2010) against baseline emissions (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 9, to determine potential control effectiveness, if any. Additionally, the Division evaluated the baseline heat input, capacity factor, and hours of operation pre-upgrade (2006 – 2008) and post-upgrade (June 2009 – June 2010) to evaluate whether the data was consistent with baseline information, and whether there was enough information to determine if a tighter emission limit is warranted, in Table 10. This information allows the Division to set a more relevant emission limit for Craig Unit 3 using representative actual emissions.

**Table 9: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)**

| Unit and Timeline | Maximum 30-day rolling emission rate (lb/MMBtu) | Average 30-day rolling emission rate post-control (lb/MMBtu) |
|---|---|---|
| Craig Unit 3 – post control (June 2009 – June 2010) | 0.1350 | 0.1081 |
| Craig Unit 3 – pre-control (2006 – 2008) | 0.1412 | 0.1088 |

**Table 10: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)**

| Unit and Timeline | Capacity Factor (Heat Input %) | Hours of Operation (% of total possible operating hours) |
|---|---|---|
| Craig Unit 3 – June – December 2009 | 98.1% | 95.5% |
| Craig Unit 3 – January – June 2010 | 89.7% | 96.1% |
| Craig Unit 3 – June 2009 – June 2010 Average | 93.9% | 95.8% |
| Craig Unit 3 – pre-control (2006 – 2008) | 86.4% | 96.3% |

The Division notes that there are not significant differences between the maximum or average 30-day rolling emissions before and after the turbine and control upgrades. Similarly, the capacity factor and hours of operation do not change discernibly. Therefore, the Division concludes that post-upgrade operations may be used in determining a tighter $SO_2$ emission limit in this reasonable progress.

Table 11 summarizes each available technology options and technical feasibility for $SO_2$ control on Craig Unit 3.

**Table 11: Craig Unit 3 SO2 Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Wet FGD | 52-98%, median 90%[8] | Y – not evaluated |
| Dry FGD | 70 – 90% | Y - installed |
| DSI (Trona) | 60-65% | Y – not evaluated, will not provide further SO2 control |
| Fuel switching – different coal type | None | Y – will not provide further SO2 control |
| Use of performance additives | None | N |
| Use of more reactive sorbent | None | N |
| Increase the pulverization level of sorbent | None | N |
| Engineering redesign of atomizer or slurry injection system | None | N |

[8] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

**Step 4: Evaluate Impacts and Document Results**

Factor 1: Cost of Compliance

A more stringent emission limit is not anticipated to result in any increased costs. Thus, this factor does not influence the selection of controls.

Factor 2: Time Necessary for Compliance

A more stringent emission limit is not anticipated to result in any system upgrades or changes and can be implemented as soon as the SIP is approved. Thus, this factor does not influence the selection of controls.

Factor 3: Energy and Non-Air Quality Impacts

There is not any negative energy or non-air quality impacts related to a more stringent emission limit. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 12 shows the number of days pre- and post-control. Table 13 depicts the visibility results (98$^{th}$ percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

**Table 12: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour SO2 rates | 3 | 0.326 | Mt. Zirkel Wilderness | 239 | --- | --- | 173 | --- | --- |
| Dry FGD | 3 | 0.150 | | 239 | 233 | 6 | 173 | 170 | 3 |
| Dry FGD | 3 | 0.070 | | 239 | 230 | 9 | 173 | 168 | 5 |

**Table 13: Visibility Results – $SO_2$ Control Options**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact)* | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) |
| Max 24-hour SO2 rates | 3 | 0.326 | 5.20 | --- | --- |
| Dry FGD | 3 | 0.150 | 4.94 | 0.26 | 5% |
| Dry FGD | 3 | 0.070 | 4.82 | 0.38 | 7% |

Step 6: Select RP Control

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets Division website, the state has determined that this emissions rate is achievable without additional capital investment.

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is dry FGD controls at the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

## B. Filterable Particulate Matter ($PM_{10}$)

Craig Unit 3 is equipped with pulse jet fabric filter (PJFF) baghouses to control PM/$PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 14 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >95% control. The current Colorado construction permit limit is 0.013 lb/MMBtu for filterable PM emissions and 0.012 lb/MMBtu for filterable $PM_{10}$ emissions and also limits total PM and $PM_{10}$ (filterable and condensable) emissions to 0.022 and 0.020 lb/MMBtu respectively (Condition 4). The most recent stack test data is used to determine

compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

**Table 14: Craig Unit 3 Stack Test Results (August 2009)**

| Pollutant | Unit 3 (lb/MMBtu) |
|---|---|
| Total PM | 0.013 |
| Filterable PM | 0.0091 |
| Condensable PM | 0.0035 |
| Total $PM_{10}$ | 0.007 |
| Filterable $PM_{10}$ | 0.0035 |
| Condensable $PM_{10}$ | 0.0035 |
| PM Control efficiency | 99.5% |
| $PM_{10}$ Control efficiency | 98.8% |

A Division review of EPA's RBLC revealed recent BACT PM/$PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The State has determined that the existing Unit 3 fabric filter baghouse and regulatory emissions limit of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/$PM_{10}$.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies
Tri-State identified five options for $NO_x$ control:
New/modified Low $NO_x$ Burners (LNBs) with Overfire Air (OFA) system (next generation)
Advanced OFA system or Rotating overfire Air (ROFA)
Neural network system combustion controls
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options
*LNBs with OFA Upgrades:* TriState contracted with ACT to modify the existing Craig 3 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-$NO_x$ Babcock & Wilcox 4Z burners such as those in use at Craig Unit 3. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT

upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed $NO_x$ reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Unit 3.

*Advanced OFA system – rotating overfire air system (ROFA):* ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

TriState contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Unit 3. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[9]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

*Neural network system combustion controls:* TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 3 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 3 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. TriState states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential $NO_x$ reductions. Neural network system combustion controls appear to be technically feasible for Craig Unit 3.

*SNCR:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Unit 3. Tri-State conducted a site-specific SNCR study

[9] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

*SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

While a lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for Craig, a retrofit SCR system, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected, although Tri-State asserts that the unit cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Unit 3.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[10] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[11] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

***LNB/SOFA/LNB+SOFA:* Craig Unit 3 is equipped with low-$NO_x$ burners with over-fire air (LNB+OFA) as part of a construction permit modification.**

Table 1 illustrates that this system achieves about 39% $NO_x$ reductions (based on actual emissions) on Unit 3.

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[12]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

[10] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[11] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[12] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[13] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Unit 3 to determine control efficiencies and annual reductions.

*LNBs with OFA Upgrades:* TriState noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% $NO_x$ reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

*Neural network system combustion controls:* TriState noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% $NO_x$ reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

*SNCR:* Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous $NO_x$ reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% $NO_x$ control. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

[13] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

*SCR:* Tri-State stated in the May 14, 2010 submittal the expected emission rate for Craig Unit 3 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[14]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve $NO_x$ reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[15] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% $NO_x$ emission reductions. Table 15 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

**Table 15: SCR Control Efficiency Comparison**

| Unit | Baseline (lb/MMBtu) | Control Efficiency (%) | | Resultant Emissions (lb/MMBtu) | |
|---|---|---|---|---|---|
| | | Tri-State Estimate | Division Estimate | Tri-State Estimate (annual average) | Division Estimate (annual average) |
| Craig Unit 3 | 0.283 | 71.8 | 75.2 | 0.080 | 0.070 |

Table 16 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 16: Craig Unit 3 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| LNB + OFA | 25-45% | Y – installed |
| Air Staging – overfire air (OFA) | 5-40% | Y – installed |
| Ultra-Low $NO_x$ Burner (ULNB) Upgrade/Refinements | 0 – 2% (TriState) | Y |
| Neural network system | 0 – 5% (TriState) | Y |
| SNCR | 10 – 40% | Y |
| Rotating overfire air (ROFA) | 45 – 65% | N |
| SCR | 75 – 90% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Coal reburn+SNCR | n/a | N |

[14] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

[15] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

*Low $NO_x$ burner upgrades:* Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low $NO_x$ burners with overfire air. Ultra-low $NO_x$ burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.[16] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

*Neural network system:* TriState did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that TriState contacted.[17] It is unknown why TriState will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

*SNCR:* A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[18] The Tri-State-estimated SNCR costs for operating expenses are 70% for Craig Unit 3. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[19]

[16] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.
[17] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."
[18] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[19] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Unit 3 (at 15% control efficiency) is approximately $4,887 per ton. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (comparable to Unit 3) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor. [20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[22] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division inquired about the reagent and auxiliary power costs; Tri-State responded on July 30, 2010 adjusted the auxiliary power and lost generation costs for all of the Craig Units for both SNCR and SCR. Tri-State also provided further information regarding the cost of potential reagent options. The costs for these two items remain higher than other Colorado facility estimates; however, Tri-State has provided adequate information detailing the reasoning for power and reagent costs. The Division and Tri-State still do not completely concur on other cost items, including an annual 3% escalation rate for capital material, capital labor, capital indirect, and operation and maintenance. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division will use Tri-State's capital and operation/maintenance costs for this analysis in the absence of additional information at this time.

*SCR:* Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving $NO_x$ emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[23,24 25,26] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 17 and Table 18 depict controlled $NO_x$ emissions and control cost comparisons.

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[20] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[22] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[23] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[24] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[25] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[26] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

**Table 17: Craig Unit 3 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 5,693 | 0.283 | |
| Combustion control refinements | 2 | 5,579 | 0.277 | 0.32 |
| Neural network system | 5 | 5,408 | 0.268 | 0.31 |
| SNCR | 15 | 4,839 | 0.240 | 0.28 |
| SCR | 75 | 1,412 | 0.070 | 0.08 |

**Table 18: Craig Unit 3 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Combustion control refinements | 114 | $122,000 | $1,071 | $1,071 |
| Neural network system | 285 | $280,000 | $984 | $925 |
| SNCR | 854 | $4,173,000 | $4,887 | $4,887 |
| SCR | 4,281 | $29,762,387 | $6,952 | $7,466 |

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

*LNB Upgrades/Neural network system(s):* There are no known non-air quality impacts associated with upgrades on low-$NO_x$ burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/ SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

**Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour 2nd | 3 | 0.365 | Mt. Zirkel Wilderness | 239 | --- | --- | 173 | --- | --- |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| half 2009 NOx rate | | | | | | | | | |
| 2009 New LNBs | 3 | 0.283 | | 239 | 234 | 5 | 173 | 170 | 3 |
| SNCR | 3 | 0.240 | | 239 | 233 | 6 | 173 | 166 | 7 |
| SCR | 3 | 0.070 | | 239 | 224 | 15 | 173 | 149 | 24 |

**Table 20: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) |
| Max 24-hour 2nd half 2009 NOx rate | 3 | 0.365 | 5.20 | --- | --- |
| 2009 New LNBs | 3 | 0.283 | 4.99 | 0.21 | 4% |
| SNCR | 3 | 0.240 | 4.88 | 0.32 | 6% |
| SCR | 3 | 0.070 | 4.41 | 0.79 | 15% |

Step 6: Select RP Control

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Craig Unit 3 is SNCR control at the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

For SNCR at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan.

V. Reasonable Progress Evaluation of Ash Hauling & Storage (P204) and Limestone Hauling (P201)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 96OPMF155.

Ash hauling (P204) is controlled with two methods to minimize fugitive emissions:

- Ash deposited in trucks for transport to disposal areas shall be sufficiently moist (Condition 8.2).
- The scrubber sludge/ash haul road servings Units 1, 2, and 3 shall be treated with magnesium chloride or equivalent as a dust suppressant. The magnesium chloride shall be applied according to manufacturer's specifications. The frequency of application shall be according to manufacturer's recommendations (Condition 8.3).

Limestone hauling (P201) activities are controlled several ways to minimize fugitive emissions:

- Opacity limitations of 20% except under certain operational conditions (U.S. EPA Reference Method 9) (Conditions 6.2, 11.2, and 11.3)
- Unloading facilities are vented to a baghouse (Condition 6.3)
- All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their in the pollution control system (Condition 6.4)

These existing controls and corresponding emission limits in Section II, Conditions 6 and 8 of Operating Permit 96OPMF155 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

## VI. Reasonable Progress Evaluation of Units 1 & 2

Units 1 and 2 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Units 1 and 2 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available $NO_x$, $SO_2$, and $PM/PM_{10}$ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for $NO_x$, $SO_2$, or $PM/PM_{10}$ for Units 1 and 2 at Craig Station.

# HEATER-TREATER SOURCE CATEGORY

**NOx Emission 4-Factor Analysis for Reasonable Progress (RP)**

## I. Source Description

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to the gas plant. Generally, the contaminants include liquid hydrocarbons and water. The composition of the liquid hydrocarbons (oil and condensate) can vary by gas field but the majority of gas wells in Colorado are located in the Denver-Julesburg (DJ) Basin which produces a condensate liquid.

The heater-treater is a combination of a heater, free-water knockout, and oil/condensate and gas separator. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead. Since chokes in the wellhead restrict the flow of the oil and gas from the well, temperatures may drop due to the pressure changes of the choke. This may cause the water or hydrates to freeze and plug the well, thereby slowing or stopping the condensate and gas production. Two diagrams at the end of this document show examples of heater-treaters.

Information regarding heater-treater emissions and control strategies is scarce. The paucity of information is likely due to the very low emissions associated with each heater-treater that very often falls below regulatory thresholds. However, the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018.

## II. Heater-Treater Source Category Emissions - Statewide

| Pollutant | Heater-Treater Emissions (tpy) | 2018 Annual Emissions (tpy) |
|---|---|---|
| CO | 0.18[1] | 4,809 |
| $NO_2$ | 0.88[1] | 22,901 |
| $PM_{10}$ | negligible[2] | negligible |
| $SO_2$ | Negligible[3] | negligible |

Notes:

1. Source: "Final Report – Oil and Gas Emission Inventories for the Western States", by ENVIRON International Corporation for Western Governors' Association, December 27, 2005
2. Source: AP-42, 5th Edition, Volume 1, Chapter 1, Section 1.4.3
3. Source: "A Comprehensive Oil and Gas Emissions Inventory for the Denver-Julesburg Basin in Colorado," by ENVIRON International Corporation, May 2008

## III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Five technologies have been identified to lower NOx emissions from heater-treaters:

*Technology #1 - Lowering the heater-treater temperature*

*Technology #2 - Installing insulation on the separator*

*Technology #3 - Retrofitting with low-NOx burners*

*Technology #4 - Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)*

*Technology #5 - Using central gathering facilities*

*Technology #1:* This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "…heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."

*Technology #2:* This technology (installing insulation on the separator) was identified by the Four Corners Air Quality Task Force in 2007. This technology would reduce combustion emissions because it would reduce fuel use.

*Technology #3:* This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th Edition, Volume 1, Chapter 1, Section 1.4.4: "Low $NO_x$ burners reduce $NO_x$ by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal $NO_x$ formation."

*Technology #4:* This technology (adding NSCR or SCR) involves adding post-combustion control equipment to treat engine exhaust.

*Technology #5:* This technology (central gathering facilities) is being used by some companies, including in the Piceance Basin and in the Jonah/Pinedale region of Wyoming. Other terms include central collection facilities, liquid gathering systems, or 3-phase gathering systems. In some cases, produced natural gas is separated into two or three phases (gas and liquids [produced water and condensate] or gas, produced water, and condensate) at the wellhead and those liquid streams are sent to central gathering facilities. In other cases, including a facility in the Piceance Basin, produced gas (including the liquids) is sent directly to the central gathering facilities. In those cases, emissions from heater-treaters would be reduced because fewer heater-treater devices would be required.

Step 2: Eliminate Technically Infeasible Options

*Technology #1:* This technology is technically feasible.

*Technology #2:* This technology is technically feasible.

*Technology #3:* The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: "Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction." It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-$NO_x$ burners are not commercially available for very small combustion sources such as heater-treaters.

*Technology #4:* A heater-treater is a combustion device that is similar to internal combustion engines where the application of NSCR and SCR on engines smaller than 100 hp is not practical or technically feasible. Moreover, the cost per unit of power is higher, and there are uncertainties as to whether the proper exhaust temperature for optimum performance can be reliably maintained. Consequently, NSCR and SCR may not be commercially available for many small engines. (source: Four Corners Air Quality Task Force document available at www.nmenv.state.nm.us/aqb/4C/Docs/ArgonneRICEmat.DOC ). Similarly, for small fuel burning equipment, such as heater-treaters, the availability of post combustion controls is anticipated to be unavailable and therefore technically infeasible.

*Technology #5:* This technology is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

*Technology #1:* The EPA Natural GasSTAR in PRO Fact Sheet No. 906 regarding lowering heater-treater temperatures was written from the methane reduction perspective. Emission reductions for NO2 and CO were not provided.

*Technology #2:* The Four Corners Air Quality Task Force did not provide the control effectiveness of installing insulation and additional information on the effectiveness of such control appears to be unavailable.

*Technology #5:* Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.

Step 4: Evaluate Impacts and Document Results

**Factor 1: Costs of Compliance**

*Technology #1 - Lowering the heater-treater temperature*: Although the EPA Natural GasSTAR fact sheet was written with methane reductions in mind, the costs of implementing the control technology also applies to combustion emission reductions. Capital costs range from $1,000 to $10,000. Annual operating and maintenance costs are $100 to $1000. The payback, through incremental labor and fuel gas savings, is less than one year.

*Technology #2 - Installing insulation on the separator*: Installing insulation on heater-treaters will reduce fuel usage and is economically feasible where there is a payback that meets an operators respective investment targets (e.g., ROI or NPV). For older units where the remaining life of the equipment is limited, the economics may not justify the application of insulation.

*Technology #5 – Centralized gas well gathering facilities to reducing the number of Heater-Treaters:* The cost of removing a group of heater-treaters and replacing them with a central gathering facility will vary due to many parameters, including topography, composition of the produced natural gas, number of heater-treaters being removed, and mineral rights. Topography may cause difficulties in dealing with large slugs of liquids; frequent pigging may be required to move liquids to the central gathering facility. It would be more cost efficient to implement this technology on a new field, rather than retrofitting an existing field that already has infrastructure based on wellhead separation. Typically when a well is drilled there are multiple ownerships in the well due to land and mineral rights. This requires that volumes be allocated back to each specific well for proper royalty treatment. To track this requires equipment at each well, which increases capital and operating costs and reduces the savings from eliminating equipment at each wellhead. This allocation issue goes away when a company owns all associated mineral and land rights. Cost savings include recovery of product that was previously lost to the atmosphere, reduced truck traffic to wellheads, and reduction of condensate and water tanks.

**Factor 2: Time Necessary for Compliance**

*Technology #1 - Lowering the heater-treater temperature*: Additional time for achieving compliance with this technology is not anticipated.

*Technology #2 - Installing insulation on the separator*: Additional time for achieving compliance with this technology is not anticipated.

*Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters:* The additional time necessary to comply with centralizing gas well gathering would be very site specific and would likely vary depending on gas well density and topographical barriers.

**Factor 3: Energy Impacts and Non Air-Quality Environmental Impacts**

*Technology #1 - Lowering the heater-treater temperature*: Lowering the heater-treater temperature will reduce fuel use. There are not any non air-quality impacts.

*Technology #2 - Installing insulation on the separator*: Installing insulation on heater-treaters will reduce fuel use. There are not any non air-quality impacts.

*Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters:* It is more energy efficient to operate a central gathering facility rather than multiple individual heater-treaters. There are not any non air-quality impacts.

**Factor 4: Remaining Useful Life**

*Technology #1 - Lowering the heater-treater temperature*: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

*Technology #2 - Installing insulation on the separator*: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

*Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters:* Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) If heater-treaters were removed and replaced with a central gathering facility, the heater-treaters would not be used for their entire service.

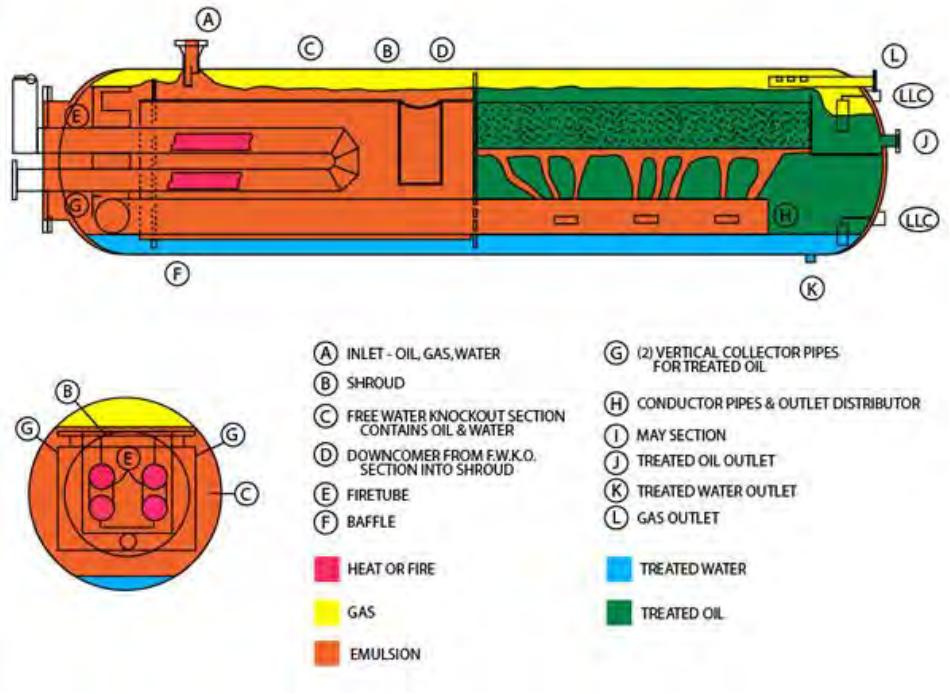
Step 5: Select Reasonable Progress Control

Currently, heater treaters are not regulated (issued permits) by the Division as they fall under an exemption for fuel burning equipment that uses gaseous fuel and has a design rate of less than or equal to 5 million BTUs/hour (AQCC Regulation 3, Part A, II.D.1.k). Generally, reports from source operators (provided to the Division on emission inventory reporting forms) indicate that a typical heater-treater design rate is about half of the exemption threshold.

Due to the lack of sufficient data, the Division is not able to make a control technology determination for heater-treaters in this planning period. The Division intends to reassess this category in the next planning period.

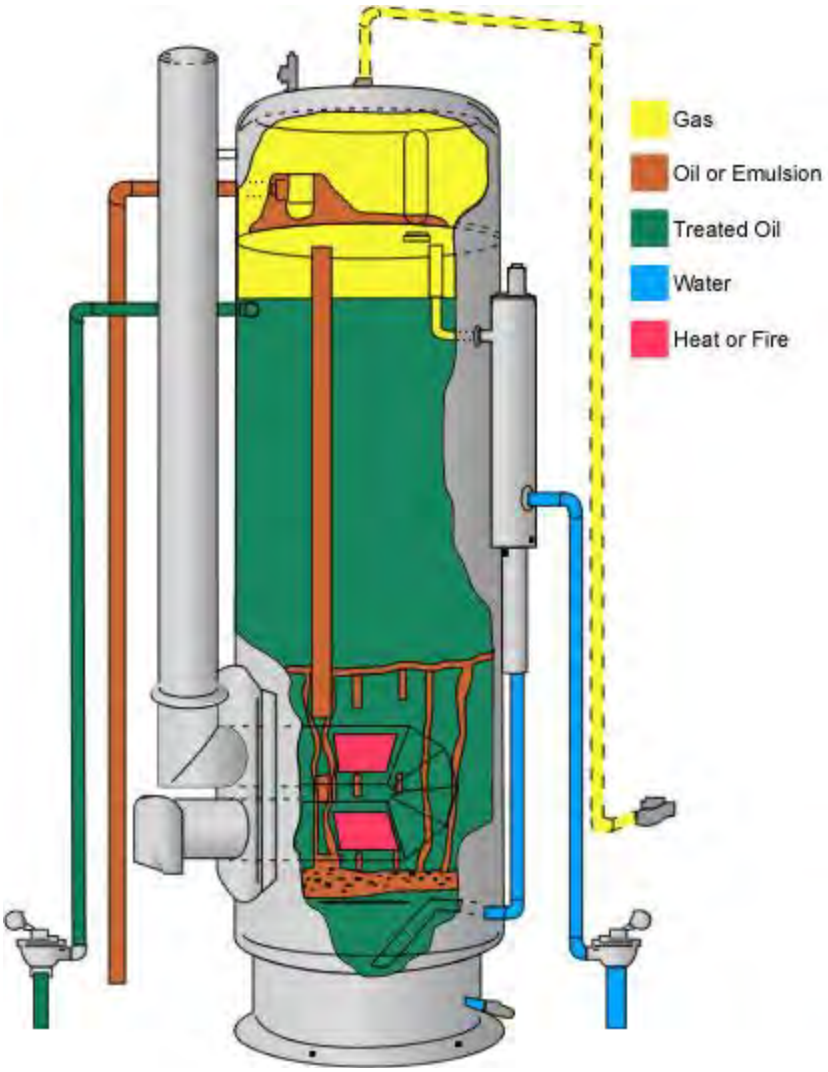
The below diagrams provide basic information on the typical heater-treater designs.

Diagram 1: Horizontal Heater-Treater




This diagram was provided by KW International. Further explanation about heater-treaters is available at http://www.kwintl.com/oil-treating.html.

Diagram 2: Vertical Heater-Treater




This diagram was provided by KW International. Further explanation about heater-treaters is available at http://www.kwintl.com/oil-treating.html.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options**
**For**
**Holcim Portland Plant, Florence, Colorado**

## I. Source Description

Owner/Operator: Holcim (US) Inc.
Source Type: Portland Cement Manufacturing (dry process)
SCC (Cement Plant): 30500623
Kiln Type: Preheater/Precalciner Kiln

The Holcim Portland plant is located in Fremont County on Highway 120 near the town of Florence, Colorado, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park. Figure 1 below provides an aerial perspective of the Portland Plant site.

**Figure 1: Holcim Portland Plant Aerial Perspective**



In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NOx, SO2, and PM/PM10 emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 mmBtu per hour of fuel input with nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM10, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NOX precalciner, indirect firing, Low-NOX burners, staged combustion and a Linkman Expert Control System for NOX, and by the use of good combustion practices for both NOX and SO2.

For this analysis, the Division also relied on the existing construction permit, historical information regarding the Holcim facility, and information about similar facilities to determine RP for NOx, SO2, and PM10. EPA‟s BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

The Division has elected to set a de minimis threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration (PSD) levels. The Division defines “unit” as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as “any building, structure, facility,

equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control1." These levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM10 emissions exceed the PSD significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis for the Portland Plant, though it did submit limited information on the feasibility of post-combustion NOX controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. The previous September 14, 2010 version of this document has been revised to reflect this additional information.

## II. Source Emissions

Table 1 summarizes the NOX, SO2 and PM10 actual emissions for the period of 2007-2009. Table 2 summarizes each unit at the facility and applicable NOx, SO2 and PM10 actual emissions.

Table 1 – Summary of Plant-Wide Emissions

| Year | Pollutant (1, 2) | | |
|---|---|---|---|
| | PM10 (tpy) | NOx (tpy) | SO2 (tpy) |
| 2007 | 262.05 | 2,447.30 | 189.80 |
| 2008 | 268.98 | 2,294.60 | 306.66 |
| 2009 | 183.26 | 1,251.66 | 297.14 |

Notes:
(1) Emission data from CDPHE – PTS data base.
(2) Annual emissions are less than permitted emissions due in part to economic conditions resulting in less than full production.

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Table 2 – Summary of Emissions by Unit Process

| AIRS ID | Process | Pollutant | Emissions(2,3) (tons per year) | | | |
|---|---|---|---|---|---|---|
| | | | 2007 (1) | 2008 | 2009 | Average |
| 101A | Top soil removed<br>Topsoil hauled<br>Wind erosion | PM10 (fug) | ---- | 1.14 | 0.57 | 0.855 |
| 101B | Explosives | PM10 (fug)<br>NOx<br>SO2 | ---- | 0.29<br>7.47<br>0.88 | 0.20<br>4.99<br>0.59 | 0.245<br>6.23<br>0.735 |
| 101C | Overburden removed/hauled | PM10 (fug) | ---- | 14.43 | 11.41 | 12.92 |
| 101D | Raw material removed/hauled | PM10 (fug) | ---- | 25.91 | 16.68 | 21.295 |
| 101E | CKD disposed/hauled | PM10 (fug) | ---- | 0.40 | 0.60 | 0.50 |
| 101F | Disturbed Area | PM10 (fug) | ---- | 83.61 | 83.61 | 83.61 |
| 101G | Mined land Reclamation | PM10 (fug) | ---- | 0 | 0 | 0 |
| 102A | Unload Crusher #1 | PM10 (fug) | ---- | 0.01 | 0 | 0.005 |
| 102B | Unload Crusher #2 | PM10 (fug) | ---- | 0.01 | 0.01 | 0.01 |
| 102C | Crusher #1 | PM10 | ---- | 0.03 | 0.02 | 0.025 |
| 102D | Transfer to secondary crusher | PM10 | ---- | 0.01 | 0 | 0.005 |
| 102E | Secondary crusher | PM10 | ---- | 0.02 | 0.01 | 0.015 |
| 102F | Crusher #2 | PM10 | ---- | 0.64 | 0.41 | 0.535 |
| 102G | Transfer to storage silo | PM10 | ---- | 0.06 | 0.03 | 0.045 |
| 102H | Transfer to blending hall | PM10 | ---- | 0.19 | 0.13 | 0.16 |
| 102J | Transfer outside materials | PM10 | ---- | 0 | 0 | 0 |
| 102K | Pre-Blend Hall activities | PM10 | ---- | 0.18 | 0.11 | 0.145 |
| 102L | Transfer from Bins | PM10 | ---- | 0.15 | 0.10 | 0.125 |
| 103A | Coal unloaded | PM10 (fug) | ---- | 0.98 | 0.68 | 0.83 |
| 103B | Coal Stockpile/Coal stored | PM10 (fug) | ---- | 0.18 | 0.12 | 0.15 |
| 103C | Coal Handled | PM10 | ---- | 0.10 | 0.07 | 0.085 |
| 103D | Coal screened/. Crushed | PM10 | ---- | 0.09 | 0.06 | 0.075 |

| AIRS ID | Process | Pollutant | Emissions(2,3) (tons per year) | | | |
|---|---|---|---|---|---|---|
| | | | 2007 (1) | 2008 | 2009 | Average |
| 103E | Coal Transferred | PM10 | ---- | 0.01 | 0.01 | 0.01 |
| 104 | Unloading additives | PM10 (fug) | ---- | 0.05 | 0.04 | 0.045 |
| 105 | Coal transferred | PM10 | ---- | 0.01 | 0.01 | 0.01 |
| 106 | Raw material Blend | PM10 | ---- | 0.15 | 0.10 | 0.125 |
| 107 | Coal Mill | PM10 | ---- | 5.16 | 1.52 | 3.34 |
| 108 | Raw Material Milled | PM10 | ---- | 4.28 | 2.76 | 3.52 |
| 109 | Raw Meal Elevated | PM10 | ---- | 2.68 | 1.73 | 2.205 |
| 110 | Raw Meal Handled | PM10 | ---- | 1.07 | 0.69 | 0.83 |
| 111 | Kiln Operations | PM10<br>NOx<br>SO2 | 68.17<br>2,439.7<br>188.9 | 47.23<br>2,287.04<br>305.76 | 13.9<br>1,246.55<br>296.55 | 43.1<br>1,931.1<br>263.7 |
| 112 | Cement clinker cooler | PM10 | ---- | 21.52 | 6.34 | 13.93 |
| 113 | Cement clinker stored | PM10 | ---- | 0.05 | 0.03 | 0.04 |
| 114 | Cement clinker handled | PM10 | ---- | 0.06 | 0.04 | 0.05 |
| 115 | Total cement produced | PM10 | 59.62 | 52.12 | 37.61 | 32.38 |
| 116 | Cement handled | PM10 | ---- | 1.78 | 1.29 | 1.485 |
| 117 | Cement bagged | PM10 | ---- | 0. | 0 | 0 |
| 118 | Cement bulk loadout | PM10 | ---- | 2.04 | 1.32 | 1.68 |
| 119 | Cement product hauled | PM10 (fug) | ---- | 1.00 | 0.64 | 0.82 |
| 135 | Clinker import | PM10 | ---- | 0 | 0 | 0 |
| 138 | Tire shredder | PM10 (fug) | ---- | 0.29 | 0.08 | 0.185 |
| 139 | Clinker reclaim | PM10 | ---- | 0.26 | 0.08 | 0.17 |
| 142 | Tire debeader | PM10<br>NOx<br>SO2 | ---- | 0.01<br>0.09<br>0. | 0<br>0.02<br>0 | 0.005<br>0.055<br>0 |
| 144 | Tire shredder | PM10 (fug) | ---- | 0.82 | 0.23 | 0.523 |
| 145 | Clinker export | PM10 (fug) | ---- | ---- | 0.02 | 0.02 |

Notes:

1) A different reporting format was used in 2007.

2) Production has been limited in recent years due to economic factors. The plant is permitted to produce up to 1,873,898 tons of clinker per year. Production in 2008 = 1,332,888 tons and in 2009 = 914,193 tons. Emissions would be higher if the plant were operating at its permitted production level.

3) For some emission points, permit limits have been decreased over the last several years so that current permit limits are now lower than historical actual emissions.

Because clinker production in 2009 was significantly lower than in previous recent years, due in large part to challenging economic conditions, the state instead included 2004 and 2005 in the baseline calculation to represent a more realistic depiction of anticipated annual production and emissions for the plant. Table 3 presents emissions and production data for the 2004, 2005, 2006, 2007 and 2008 baseline years:

Table 3 – Kiln System Production and Emissions (2004 through 2008)

| Year | Actual Emissions/Production | | | | | Projected Annual Emissions at Full Production of 1,873,898 tpy clinker | |
|---|---|---|---|---|---|---|---|
| | $NO_x$ (tons) | $SO_2$ (tons) | Clinker (tons) | $NO_x$ (lbs/ton) | $SO_2$ (lbs/ton) | $NO_x$ (tons) | $SO_2$ (tons) |
| 2004 | 2,741.3 | 780.6 | 1,641,423 | 3.34 | 0.95 | 3,129.6 | 891.2 |
| 2005 | 2,572.3 | 371.5 | 1,642,740 | 3.13 | 0.45 | 2,934.3 | 423.8 |
| 2006 | 3,098.0 | 366.4 | 1,686,451 | 3.67 | 0.43 | 3,442.3 | 407.1 |
| 2007 | 2,439.7 | 188.9 | 1,361,523 | 3.58 | 0.28 | 3,357.8 | 260.0 |
| 2008 | 2,287.0 | 305.8 | 1,332,888 | 3.43 | 0.46 | 3,215.3 | 429.9 |
| Avg | 2,627.7 | 402.6 | 1,533,005 | 3.43 | 0.51 | 3,215.8 | 482.4 |
| Max | 3,098.0 | 780.6 | 1,686,451 | 3.67 | 0.95 | 3,442.3 | 891.2 |

## III. Units Evaluated for Control

As discussed above, the only emission points whose current permitted level of emissions exceed the *de minimis* thresholds are the kiln system, quarry and finish mill. These emission points will be evaluated as a part of this reasonable progress analysis. The other emission points at the Portland Plant will not be considered further.

## IV. Reasonable Progress Evaluation of the Kiln System

### *A. Sulfur Dioxide ($SO_2$)*

Step 1: Identify All Available Technologies

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. The wet lime scrubbing process involves passing the flue gas from the kiln system through a sprayed aqueous calcium-based suspension that is contained within the scrubbing device. In the wet lime scrubber, the $SO_2$ reacts with the scrubbing reagent to form $CaSO_4$ that is collected and retained as aqueous sludge. The sludge is then dewatered and disposed.

Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the $SO_2$ emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

Step 2: Eliminate Technically Infeasible Options

The currently installed combination of good combustion practices, the inherent scrubbing nature of the cement manufacturing process, and the wet lime scrubber represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

**Factor 1: Cost of Compliance**

The currently installed and operating controls are assumed to be cost-effective.

**Factor 2: Time Necessary for Compliance**

The controls are already installed and operating.

**Factor 3: Energy and Non-Air Quality Impacts**

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination.

**Factor 4: Remaining Useful Life**

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

**Factor 5 (optional): Evaluate Visibility Results**

CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO2 emission rate of 99.17 pounds per hour (lbs/hour), a NOx emission rate of 837.96 lbs/hour, and a PM10 emission rate of 19.83 lbs/hour. The modeling indicated a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Because the baseline emission rates and proposed RP emission rates have been revised, this specific impact value is no longer directly associated with the emission rates discussed in this section. However, in any event, because no additional controls are proposed for SO2 emissions, there is no visibility improvement associated with SO2 emissions.

Determination

While the state has determined that the existing controls represent the top-level control technology, the state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO2. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO2 per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO2 value of 0.77 pound per ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO2 emission limit of 1.30 pounds per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO2 per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim"s wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Summary of $SO_2$ RP Determination for Kiln System

1.30 pounds of $SO_2$ per ton of clinker (30-day rolling average)

721.4 tons of SO2 per year (12-month rolling total)

## *B. Filterable Particulate Matter (PM and $PM_{10}$)*

Step 1: Identify All Available Technologies

The state has determined that the existing baghouses installed on the kiln system represent the most stringent control option. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter.

Holcim has reported nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

Step 2: Eliminate Technically Infeasible Options

The currently installed baghouses represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

**Factor 1: Cost of Compliance**

The currently installed and operating controls are assumed to be cost-effective.

**Factor 2: Time Necessary for Compliance**

The controls are already installed and operating.

**Factor 3: Energy and Non-Air Quality Impacts**

Because there are no changes to the existing controls for PM/PM10, there are no associated energy and non-air quality impacts for this determination.

**Factor 4: Remaining Useful Life**

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

**Factor 5 (optional): Evaluate Visibility Results**

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO2 emission rate of 99.17 lbs/hour, a NOx emission rate of 837.96 pounds per hour (lbs/hour), and a PM10 emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park.

As a part of our September 14, 2010 analysis, the state modeled possible visibility improvements associated with two emission rates – an emission rate of 0.08 pound of $PM_{10}$ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of $PM_{10}$ per ton of clinker (9.92 lbs/hour). This analysis assumed the emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98$^{th}$ percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change.

The state"s modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates ($NO_3$) followed by sulfates ($SO_4$).The contribution of $PM_{10}$ to the total visibility impairment was insignificant in the analysis. The level of $PM_{10}$ emissions evaluated had no discernable impact on visibility.

Determination

While the state has determined that the existing controls represent the top-level control technology, the state did assess the corresponding $PM_{10}$ emissions rates. The facility is currently permitted to emit 246.3 tpy of $PM_{10}$ from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of $PM_{10}$ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for $PM_{10}$). The actual kiln system $PM_{10}$ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of $PM_{10}$ per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of $PM_{10}$ emissions from the kiln system on visibility impairment, the state has determined that no additional $PM_{10}$ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of $PM_{10}$ (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the $PM_{10}$ emissions.

Summary of PM/PM10 RP Determination for Kiln System

246.3 tons of PM10 per year (12-month rolling total)

## *C. Nitrogen Oxides (NOx)*

Step 1: Identify All Available Technologies

There are a number of technologies available to reduce NOX emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NOX emissions from Portland cement kilns. Additional discussion on SNCR is provided below:

For SNCR, within the relatively narrow temperature window of 1600 to 2000°F, ammonia (NH3) reacts with NOx without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Above this temperature range, the NH3 is oxidized to NOx, thereby increasing NOx emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH3 could be delivered to the kiln system through the use of anhydrous NH3, or an aqueous solution of NH3 (ammonium hydroxide) or urea [(NH2)2CO]. A concern about application of SNCR technology is the breakthrough of unreacted NH3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO2, sulfur trioxide (SO3), hydrogen chloride (HCl) and/or chlorine (Cl2) to form a detached plume of PM10–PM2.5.

As part of this analysis, the state also considered the use selective catalytic reduction (SCR) as a NOX control technology. The state has determined that SCR is not commercially available for the cement kiln system at the Holcim Portland Plant. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: "However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns." Based on our research and EPA"s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for the Holcim Portland Plant for purposes of this RP analysis. Additional information regarding SCR, as developed by the state as part of its BART analysis for the CEMEX Lyons plant is provided below:

SCR refers to the reduction of NOx in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term "selective" refers to the unique ability of ammonia to react selectively with NOx. The EPA released a NOx control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns," EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

> *SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce $NO_x$ emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce $NO_x$ emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith*

*form) and promotes the $NO_x$ reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C] ), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:*

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N2 + 6\ H_2O$$

*and*

$$4\ NH_3 + 2\ NO_2 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

*The first equation is the predominant reaction because 90-95% of $NO_x$ in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a $NH_3$: $NO_x$ molar ratio of 1.05–1.1:1 to achieve a $NO_x$ conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The $NO_x$ removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to $NO_x$, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired $NO_x$ reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:*

*After the PM control device – a "low-dust" system*
*After the last cyclone without ducting – a "high-dust" system.*

*The advantages of a "low-dust" system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 $mg/m_3$ (~ 0.8 lb/t) of $NO_x$ is typically achieved from an inlet of 1,050 $mg/Nm_3$ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 $mg/m_3$. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.*

*The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.*

The design of a SCR system is expected to be site specific. According to Schreiber[2], the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 2, from Granger[3] shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NOx reduction efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350°C to 450°C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NOx reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

**Figure 2: Catalyst Performance for NOx Control and Ammonia slip at Various Temperatures**

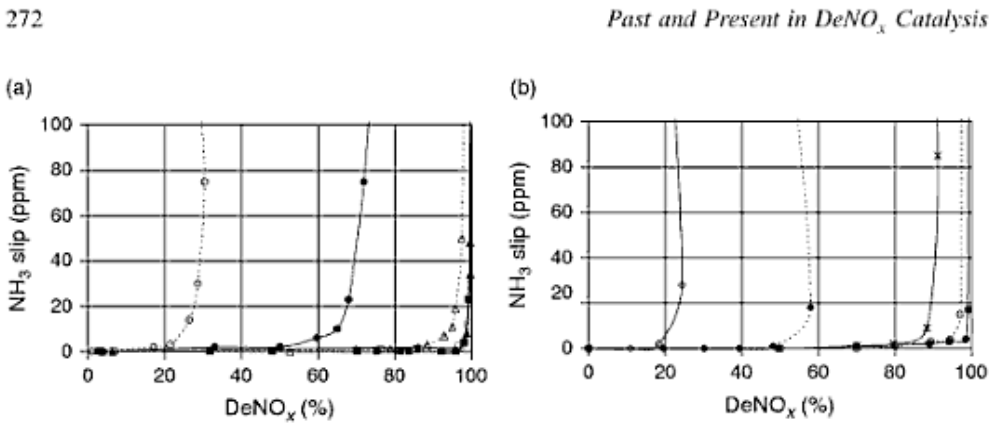



**Figure 9.9.** Performance of a coated $V_2O_5/WO_3-TiO_2$ SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) NO:$NO_2$ = 1 : 1. (◇) 120°C, (♦) 150°C, (*) 180°C, (○) 200°C, (●) 250°C, (▲) 300°C, (Δ) 350°C, (□) 400°C, and (■) 450°C. Cell density: ≈400 cpsi. $V_{cat} = 7.5\,cm^3$. Model gas investigation with 10% $O_2$, 5% $H_2O$, 1000 ppm NO or 500 ppm NO + 500 ppm $NO_2$, 0–1500 ppm $NH_3$, and balance $N_2$ in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 $h^{-1}$.

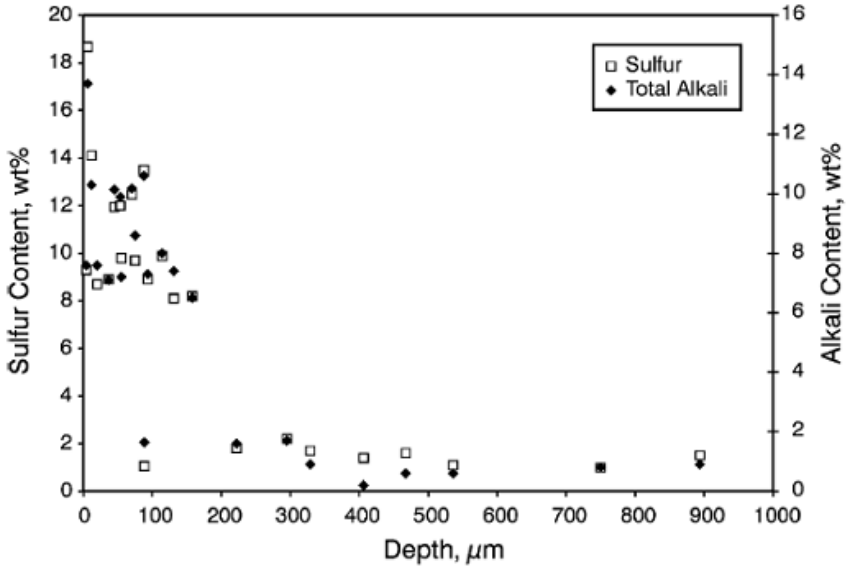
Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. A good catalyst must ensure high activity and selectivity for NOx reduction and low activity in the oxidation of SO2 to SO4. Because of the high selectivity, the catalyst will have a specific temperature window at which the NOx reduction is optimal (Granger 2007).

[2] See Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)

[3] See Granger, P. Elsevier, "Past and Present in DeNOx Catalysis: From Molecular Modeling to Chemical Engineering", (2007)

There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NOx reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson[4], alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.,* 2008, and Strege *et al.,* 2008). Figure 3 shows evidence of catalyst poisoning by both sulfur and alkalies[5]. The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NOx control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NOx reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst.

**Figure 3: Sulfur and Alkali Penetration into the pores of the catalyst**

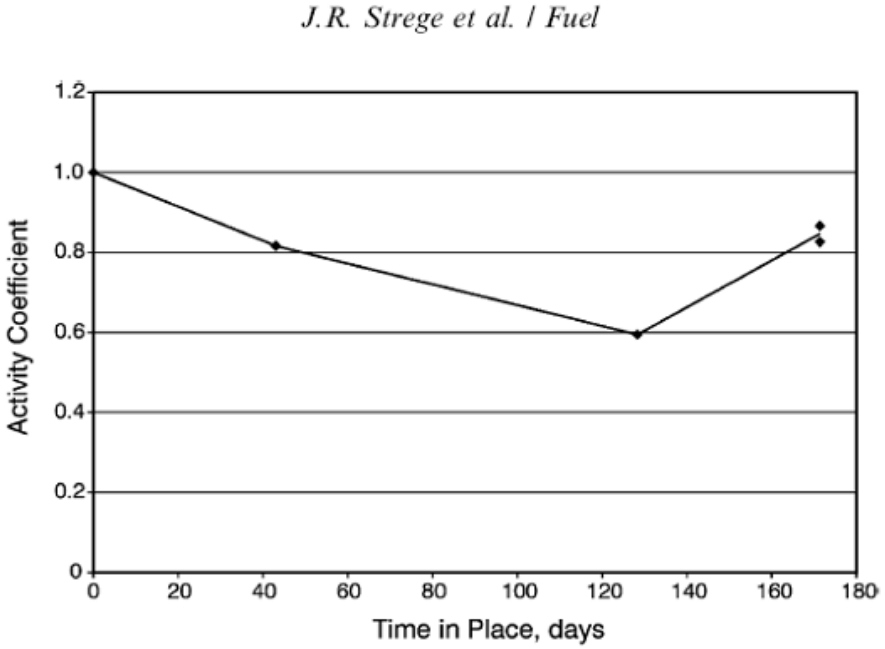



Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

Figure 3 indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NOx reduction (see Strege *et al.*, 2008).

[4] See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)
[5] See Strege, J. et al., "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

**Figure 4: Bench Scale Test Results of Catalyst Deactivation over a Period of Time**




Bench-scale test results of catalyst deactivation with time.

Figure 4 provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NOx conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro[6], a good flow distribution is needed to ensure minimal ammonia slip. The potential for ammonia slip to create visibility impairment that is readily transported into nearby Great Sand Dunes National Park exists.

The state finds that a limited use - trial basis application of an SCR control technology on three kilns in Europe does not constitute "available" control technology for purposes of Reasonable Progress at the Holcim Portland Plant. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *"The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst*." Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse.

[6] See Barbaro, P.; Bianxhini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be "available" for purposes of retrofitting such control technology on the Portland Plant. Reasonable Progress should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, given this fact and the difficulty that Holcim has had in obtaining viable vendor quotations for an SCR system, the Division has eliminated SCR as an available control technology for the Holcim Portland Plant for purposes of Reasonable Progress.

Step 2: Eliminate Technically Infeasible Options

As described above, water injection and SNCR were determined to be technically feasible and appropriate for reducing $NO_X$ emissions from Portland cement kilns.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The design of the Holcim Portland Plant does allow for the effective use of SNCR, which requires ammonia-containing compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOX to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF‟s long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of $NO_X$ per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of $NO_X$ per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy $NO_X$ limit.

Because SNCR is technically and economically feasible, the state did not further consider water injection because the levels of control associated with this option are not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

| NOx Control Technology | Estimated Control Efficiency | 30-day Rolling Average Emissions (lb/ton of Clinker) | Annual Controlled NOx Emissions (tpy) |
|---|---|---|---|
| Baseline NOx Emissions | - | 4.97 | 3,185.7[1] |
| SNCR | 45%[2] | 2.73 | 2,086.8 |

[1] Defaulted to the permit limit since the calculated baseline was higher.

[2] This is calculated based on the 50% SNCR removal efficiency and 10% bypass

Step 4: Evaluate Factors and Present Determination

**Factor 1: Cost of Compliance**

In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006. Holcim estimated that NOX emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues. Considering the concern with the ammonia slip, an overall SNCR removal efficiency of 45% was used in this analysis. This estimate was based on an installation cost of $400,000 to $600,000 and an annual cost of $2,520,000. In February 2010, Holcim also provided a general direct capital investment cost estimate of $700,000 to $1,400,000 (excluding the capability for winter operations). The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

| Holcim Portland Plant – Kiln System | | | | |
|---|---|---|---|---|
| NOx Control Technology | NOx Emission Reduction | Annualized Cost | Cost Effectiveness | Incremental Cost Effectiveness |
| | (tons/yr) | ($/yr) | ($/ton) | ($/ton) |
| Baseline NOx Emissions | - | | | |
| SNCR (45% control) | 1,098.9 | $2,520,000[1] | $2,293 | - |

[1] Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

**Factor 2: Time Necessary for Compliance**

It is anticipated that within five years or less after SIP approval, all the work necessary to study, design, construct and begin operating the SNCR system would be complete.

**Factor 3: Energy and Non-Air Quality Impacts**

SNCR systems do increase power needs to operate injection equipment, drive the pumps and fans necessary to supply reagents, and overcome additional pressure drops caused by the control equipment. Installing SNCR also increases levels of ammonia emissions, and can create a „blue plume" if ammonia rates are not adequately controlled. Other environmental factors include the storage and transportation of the selected ammonia-based reagent. For SNCR systems, these types of energy and non-air quality impacts, while necessary to address, are not generally considered significant and do not adversely affect the selection of this technology.

**Factor 4: Remaining Useful Life**

The state is not aware of any near-term limitations on the useful life of the cement kiln system, so it can be assumed that it will remain in service for a 20-year amortization period. Thus, this factor does not influence the selection of controls.

**Factor 5 (optional): Evaluate Visibility Results**

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO2 emission rate of 99.17 lbs/hour, a NOx emission rate of 837.96 pounds per hour (lbs/hour), and a PM10 emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NOx RP limitations. The following table lists the projected visibility improvements for these NOx controls, as identified by Holcim:

| Holcim Portland Plant – Kiln System | | |
|---|---|---|
| NOx Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (Δdv) |
| Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.814 | N/A |
| SNCR 45% overall NOx control efficiency Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NOx, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.526 | 0.288 |

Determination

For the kiln system, the state has determined that SNCR is the best NOx control system available with NOx RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NOx reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

Summary of NOx RP Determination for Kiln System

2.73 pounds of NOx per ton of clinker (30-day rolling average)

2,086.8 tons of NOx per year (12-month rolling total)

## V. Reasonable Progress Evaluation of the Quarry and Finish Mill

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM10 emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

Particulate Matter RP Determination for Quarry

The state has determined that the existing fugitive dust control plan and associated control measures which include: watering and the use of chemical stabilizers, compaction and re-vegetation of stockpiles, vehicle speed limitations, reclamation and sequential extraction of materials, paving, graveling and cleaning of haul roads, sequential blasting, wet drilling, and the suspension of activities during high wind events represent the most stringent control option for these types of emission sources. The existing fugitive dust control plan and the 47.9 tpy fugitive PM10 emission limit (12-month rolling total) for the quarry represent RP for PM10.

Summary of PM/PM10 RP Determination for Quarry

47.9 tons of fugitive PM10 per year (12-month rolling total)

Particulate Matter RP Determination for Finish Mill

The state has determined that the existing fabric filter baghouses and the existing emissions limits of 34.3 tpy of PM10 (12-month rolling total) for the finish mill represent the most stringent control option. Holcim has reported nominal control efficiency for the finish mill baghouses of 99.5%. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits represent RP for PM10 for the finish mill. In addition to the ton per year emission limit associated with this RP determination, the finish mill will also be subject to the recent changes to the PC MACT standard, which contains a visible emission limitation for finish mills.

Summary of PM/PM10 RP Determination for Finish Mill

34.3 tons of PM10 per year (12-month rolling total)

**Reasonable Progress (RP) Four-Factor Analysis of Control Options**
**For**
**Colorado Springs Utilities – Ray D. Nixon Power Plant**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Colorado Springs Utilities |
| Source Types: | Electric Utility Steam Generating Unit |
| SCC (EGU): | 10100222 |
| Boiler Type: | Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas |

The Nixon facility is located at 14020 Ray Nixon Road in Fountain, Colorado. This facility consists of one (1) steam driven turbine/generator unit, auxiliary boiler, the associated equipment needed for generating electricity, and two natural gas fired simple cycle combustion turbines driving electricity generators. The boiler fires low sulfur western coal as the primary fuel and can currently use No. 2 distillate oil or natural gas for an ignition fuel. The ignition fuels are used for startup of the boiler, flame stabilization, and the coal pulverizer startup. The facility also includes the various processes necessary to handle the coal, flyash and bottom ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control at appropriate point sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nixon power plant, and information about similar facilities to determine RP for $NO_x$, $SO_2$, and $PM_{10}$. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

- $NO_x$ – 40 tons per year

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

Nixon Power Plant is considered a single source with six (6) other facilities, depicted in Table 1.

**Table 1: Facilities Co-Located or Considered to be a Single Source with Nixon Power Plant**

| Emission Sources | Colorado Construction/Operating Permit # | Permit Holder |
|---|---|---|
| Coal Screen | 98PO149 | Western Resources |
| 2 Anaerobic Digestors, 4 Biogas Boilers and 2 Flares | 96OPEP152 | CSU – Clear Spring Ranch Solids & Handling |
| 2 Natural Gas Turbines | 99EP0851 | Front Range Power Company, LLC |
| 1 Coal-fired Boiler, 2 Natural Gas Turbines, Cooling Tower, Ash Handling, Coal Handling, Auxiliary Boiler | 95OPEP106 | CSU – Nixon Power Plant |
| Wastewater Treatment and 3 Internal Combustion Engines | 95EP1097 | CSU – Las Vegas Street Municipal Treatment Plant |
| Custom Anaerobic Wastewater Treatment System | 03EP0158 | CSU – Northern Water Reclamation Facility |

The two natural-gas fired combustion turbines at Front Range Power Plant (FRPP) are above the Prevention of Significant Deterioration significance level for $NO_x$. The other single source facilities emit $NO_x$, $SO_2$, and/or $PM_{10}$ below the Prevention of Significant Deterioration significance levels.

The Front Range Power Plant (FRPP) is located at 6615 Generation Drive, Fountain, Colorado. The facility produces electrical power using two natural gas combustion turbines, with two Heat Recovery Steam Generators (HRSG), and duct burners. These two combustion turbines are evaluated within the source category "Combustion Turbines" in Section 8.2.3 of the Regional Haze SIP.

Nixon Unit 1 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. CSU provided information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on February 21, March 21, May 10, and June 2, 2010. Table 2 depicts technical information for Nixon Unit 1.

**Table 2: Nixon/FRPP RP-eligible Emission Controls and Reduction (%)**

| | Nixon Unit 1 |
|---|---|
| Placed in Service | April 1980 |
| Boiler Rating, MMBtu/Hr for coal | 2,049 |
| Electrical Power Rating, Gross Megawatts | 227 |
| Description | Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing coal. The coal burner ignitors fire No. 2 fuel or spec oil & NG |
| Air Pollution Control Equipment | Western Precipitation Thermoflex Fabric Filter (baghouse) |
| Special Features | Low NOx burners placed in service in 1989 |
| Emissions Reduction (%) | $NO_x$ – 37%<br>$SO_2$ – None<br>$PM/PM_{10}$ – 99.9/99.7% |

Regulations that apply to the boiler are as follows:
For Nixon Unit 1:

- NSPS Subpart D regulates particulate matter emissions to 0.1 lb/MMBtu.
- NSPS Subpart D regulates $NO_X$ emissions to 0.7 lb/MMBtu.
- The Title V Operating Permit limits annual $NO_X$ emissions to 2853.3 tons per year.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program regulates $NO_X$ emissions to 0.50 lb/MMBtu of heat input on an annual average basis.
- NSPS Subpart D regulates $SO_2$ emissions to 1.2 lb/MMBtu.

## II. Source Emissions

Table 3 summarizes each unit at the facility and applicable $NO_x$, $SO_2$, and PM actual emissions averaged over the 2006 – 2008 timeframe with data from EPA's CAMD database, Colorado's Air Pollutant Emission Notices submitted by the facility, and Colorado inspection reports as applicable. Table 4 summarizes the $NO_x$, $SO_2$, and PM actual emissions averaged over the 2006 – 2008 timeframe (baseline) for each RP-eligible unit.

**Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit - Nixon Facility**

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| Boiler #1 | $SO_2$ (tons) | 3877.6 | 4043.1 | 4442.3 | 4121.0 |
| | $SO_2$ (lb/MMBtu) | 0.46 | 0.52 | 0.53 | 0.50 |
| | $NO_x$ (tons) | 2390.1 | 2137.0 | 2542.9 | 2356.7 |
| | $NO_x$ (lb/MMBtu) | 0.26 | 0.26 | 0.26 | 0.26 |

| | | | | | |
|---|---|---|---|---|---|
| | $PM_{10}$ (tons) | 89.24 | 82.29 | 88.78 | 86.8 |
| | $PM_{10}$ (lb/MMBtu) | 0.011 | 0.011 | 0.011 | 0.011 |
| *Auxiliary Boiler* | *$SO_2$ (tons)* | *0* | *0* | *0* | *0.0* |
| | *$SO_2$ (lb/MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *0.02* | *0.02* | *0.05* | *0.0* |
| | *$NO_x$ (lb/MMBtu)* | *1.50* | *1.50* | *1.52* | *1.51* |
| | *$PM_{10}$ (tons)* | *0* | *0* | *0* | *0.0* |
| | *$PM_{10}$ (lb/MMBtu)* | *0.000* | *0.000* | *0.000* | *0.000* |
| *Nixon Combustion Turbine 1* | *$SO_2$ (tons)* | *0.01* | *0.01* | *0.01* | *0.0* |
| | *$SO_2$ (lb/MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *0.81* | *0.61* | *0.76* | *0.7* |
| | *$NO_x$ (lb/MMBtu)* | *0.04* | *0.04* | *0.04* | *0.04* |
| | *$PM_{10}$ (tons)* | *0.23* | *0.19* | *0.25* | *0.2* |
| | *$PM_{10}$ (lb/MMBtu)* | *0.011* | *0.012* | *0.012* | *0.012* |
| *Nixon Combustion Turbine 2* | *$SO_2$ (tons)* | *0.01* | *0.02* | *0.01* | *0.0* |
| | *$SO_2$ (lb/MMBtu)* | *0.00* | *0.00* | *0.00* | *0.00* |
| | *$NO_x$ (tons)* | *0.97* | *1.67* | *0.85* | *1.2* |
| | *$NO_x$ (lb/MMBtu)* | *0.04* | *0.05* | *0.05* | *0.05* |
| | *$PM_{10}$ (tons)* | *0.27* | *0.36* | *0.23* | *0.3* |
| | *$PM_{10}$ (lb/MMBtu)* | *0.012* | *0.012* | *0.014* | *0.012* |
| Coal Reclaim Conveyor (003) | $PM_{10}$ (tons) | 25.97 | 25.97 | 21.85 | 24.60 |
| *Ash Handling/Disposal (006)* | *$PM_{10}$ (tons)* | *1.41* | *1.41* | *1.41* | *1.41* |
| Coal Handling (008) | $PM_{10}$ (tons) | 23.2 | 23.2 | 1.47 | 15.96 |
| *Ash Haul Roads & Disposal (009)* | *$PM_{10}$ (tons)* | *1.85* | *1.85* | *1.87* | *1.86* |
| *Unit #1 Cooling Tower* | *$PM_{10}$ (tons)* | *0.8* | *0.8* | *0.75* | *0.78* |
| *Four Digester Gas Boilers* | *$SO_2$ (tons)* | *10.15* | *9.03* | *9.03* | *9.40* |
| | *$NO_x$ (tons)* | *4.95* | *3.84* | *3.84* | *4.21* |
| | *$PM_{10}$ (tons)* | *0.50* | *0.35* | *0.35* | *0.40* |
| *2 Digester Gas Flares* | *$SO_2$ (tons)* | *11.0* | *11.19* | *11.19* | *11.13* |
| | *$NO_x$ (tons)* | *2.61* | *2.65* | *2.65* | *2.64* |
| | *$PM_{10}$ (tons)* | *0.54* | *0.40* | *0.40* | *0.45* |
| *Sludge Injection & Unpaved Roads* | *$PM_{10}$ (tons)* | *8.90* | *8.90* | *8.90* | *8.90* |

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day $NO_x$ rolling average is likely about 0.58 lbs/MMBtu for Boiler 1).

Units *italicized* in Table 2 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

**Table 4. Nixon Unit 1 Baseline Emissions**

| Pollutant | Nixon Unit 1 | |
|---|---|---|
| | Annual Emissions* (tpy) | Annual Emissions** (lb/MMBtu) |
| $NO_x$ | 2,357 | 0.258 |
| $SO_2$ | 4,121 | 0.453 |
| $PM_{10}$ | 87 | 0.002*** |

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions and for $PM_{10}$ emissions for the turbines.
***The $PM_{10}$ emission rate is determined from the Title V permit compliance stack test. These values are as follows: Nixon Unit 1 – 0.0021 lb/MMBtu (4/15/2008)

## III. Units Evaluated for Control

As documented by CSU, Nixon Unit 1 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

**Table 5: Coal Specifications (2006 - 2007 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| Nixon Unit 1 | 8,752 | 0.22 | 4.99 |

Table 1 lists the units at Nixon that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

**Table 6: Uncontrolled emission factors for Nixon Unit 1**

| Emission Unit | Pollutant | Fuel |
|---|---|---|
| | | Coal (sub-bituminous) (lb/ton) |
| Nixon Unit 1[2] | $NO_x$ | 7.2 |
| | $SO_2$ | 35 x %S = 7.7* |
| | $PM/PM_{10}$ | PM – 49.90**<br>$PM_{10}$ – 11.48 |

*%S = % of sulfur present in coal supply. For example, 35 x 0.22 = 7.7
**%A = % of ash present in coal supply. For example, 10 x 4.99 = 49.90

## IV. Reasonable Progress Evaluation of Nixon Unit 1

### *a. Sulfur Dioxide*

**Step 1: Identify All Available Technologies**

CSU identified one $SO_2$ control option:
Flue gas desulfurization (FGD):
Lime spray dry absorber (SDA or dry FGD)

The Division identified two additional $SO_2$ control options:
Flue gas desulfurization (FGD):
Lime or limestone-based (wet FGD)
Dry sorbent injection – Trona (DSI)

[2] EPA AP-42 Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

**Step 2: Eliminate Technically Infeasible Options**

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

*Dry FGD:* Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling $SO_2$ Emissions: A Review of Technologies[4] evaluates various $SO_2$ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

CSU's 2009 submittal states that a dry FGD (SDA) system is technically feasible. The Division concurs with this conclusion.

The Division notes that traditional wet FGD controls are possible at Nixon Unit 1 considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls at Nixon Unit 1.

It is worth noting that CSU is currently testing a new, innovative non-traditional wet scrubber control system at another facility that appears to be as effective, if not more effective, at controlling $SO_2$ emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system,

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART (Regional Haze) rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber at Nixon Unit 1 if desired and applicable. This process will be required to meet the emission limits established for the LSD technology established in this RP determination. Regardless of the technology utilized, Nixon has to meet the LSD-based RP limits within 5 years of EPA approval of the Regional Haze SIP. CSU will test the NeuStream system at this facility until December 2011, and at that time, determine the control technology that will be used to comply with the specified $SO_2$ RP limit for Nixon Unit 1.

***DSI:*** Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the $SO_2$ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the $NO_x$ present in the flue gas from NO which is colorless to $NO_2$ which has a reddish-brown color. This conversion of NO to $NO_2$ can create a brown plume from the stack which could create

opacity compliance issues. Due to variability of boiler configurations, coal composition, $NO_x$ to $SO_2$ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum $SO_2$ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum $SO_2$ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% $SO_2$ removal at another facility. In practical application, a higher $SO_2$ removal rate may be possible, while it is also possible that a lower $SO_2$ removal rate may be necessary to limit the brown plume formation. This determination would require actual $SO_2$ removal real-time testing. Therefore, since CSU notes that DSI is technically feasible for a similar facility, the Division assumes this same technology is also then technically feasible for Nixon Unit 1.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

CSU provided the Division annual average control estimates. In the Division's experience, 30-day $SO_2$ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Unit 1 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT $SO_2$ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

*Dry FGD (LSD):* Controlling $SO_2$ Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Nixon Power Plant, typically <0.5% as detailed in Table 5, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Therefore, dry FGD is evaluated at two control efficiencies level – 78% (0.010 lb/MMBtu annual average) and 82.3% (0.08 lb/MMBtu annual average) for comparison purposes.

*DSI:* Based on literature review, CSU estimated the maximum $SO_2$ removal rate that can be achieved to be 60% $SO_2$ removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

[5] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Table 7 summarizes each available technology and technical feasibility for $SO_2$ control.

**Table 7: Nixon Unit 1 $SO_2$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Wet FGD | 95% | Y |
| Dry FGD (LSD) | 75 – 85% | Y |
| DSI | 60% (CSU) | Y |

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

*Wet FGD*: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

*LSD/DSI:* CSU submitted cost estimates for a LSD system on Unit 1 on February 20, 2009. CSU provided cost estimates for the DSI system evaluated on another similar Colorado unit (CSU Drake Unit 5) on May 10, 2010.

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in Table 8. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of $CO_2$ when measured on a per MW-h basis. These estimates are for another facility, Drake Units 6 and 7, but are assumed to be directly applicable to Nixon Unit 1 as well.

**Table 8: LSD Energy Replacement Costs**

| Unit | Replacement capacity cost ($/kW-yr) | Differential energy cost ($/MW-h) |
|---|---|---|
| Drake 6/7 | 44 | 35 |

This information, including detailed capital and annual cost data, are provided as "CSU Drake BART Submittals" and "CSU Nixon RP Submittals". CSU originally generated costs using EPRI's FGD Cost model for Drake.[6] This model uses specific unit data to

[6] EPA's BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of

calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. When preparing cost estimates for Nixon, cost estimates were developed using the IECCOST program.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[7] shown in Table 9.

**Table 9: CSU-Drake $SO_2$ LSD Control Cost Comparison**

| Unit Capacity (MW) | EPA's Calculated Cost Effectiveness for MW Group ($/ton $SO_2$ Removed) | CSU Refined Cost Estimate ($/ton $SO_2$ Removed (Control System)) | Cost Differential |
|---|---|---|---|
| Drake Unit 6 – 85 MW | $2,399 | $2,579 - $2,981 | + 8% – 24% |
| Drake Unit 7 – 142 MW | $1,796 | $2,140 - $2,694 | + 19% - 50% |
| Nixon Unit 1 – 225 MW | $1,282 | $3,744 - $3,950 | + 192% - 208% |

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Unit 1 using various cost updates from the 2008 timeframe. Nixon has reflected the costs of retrofitting a facility that is moderately congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. The Division does not necessarily concur with these estimates, but will accept them for purposes of this RP analysis.

CSU only submitted DSI cost information for another facility, Drake Unit 5. The Division scaled this cost information for Units 1 in Table 10. Please see "Drake APCD Technical Analysis" and "Nixon APCD Technical Analysis" for more details.

the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

[7] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART $SO_2$ Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

For dry FGD, CSU estimated a removal rate of 80% based on 2008 average data and a resulting emission rate at the BART presumptive limits of 0.10 lb/MMBtu. The Division adjusted this removal rate using the baseline $SO_2$ emissions from Table 4 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 78 - 82%that meets the BART presumptive limit for Nixon Unit 1. This range allows the Division to determine the most reasonable RP limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Nixon APCD Technical Analysis" for more details.

Table 10 illustrates resultant $SO_2$ emissions for each technically feasible control option. Table 11 shows the $SO_2$ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 4. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average $SO_2$ emission rate is approximately 5% higher than the annual average emission rate.

**Table 10: Nixon Unit 1 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Unit 1 | | |
| | | (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 4,121 | 0.453 | |
| DSI | 60 | 1,649 | 0.181 | 0.190 |
| Dry FGD (LSD) @ 78% control | 78 | 907 | 0.100 | 0.105 |
| Dry FGD (LSD) @ 82.3% control | 82.3 | 729 | 0.080 | 0.084 |

**Table 11: Nixon Unit 1 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| DSI | 2,473 | $4,938,692 | $1,997 | $1,997 |
| Dry FGD (LSD) @ 78% control | 3,215 | $12,036,604 | $3,744 | $9,568 |
| Dry FGD (LSD) @ 82.3% control | 3,392 | $13,399,590 | $3,950 | $7,691 |

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[8], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

*Traditional Wet FGD:* Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP $SO_2$ control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of $SO_2$ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in $SO_2$ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental $SO_2$ emission reduction benefits (tons of $SO_2$ reduced annually) and visibility improvement (deciview improvement at nearest Class I

[8]Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

area) when compared to LSD or the pilot NeuStream-S FGD scrubber when applied to the Nixon Unit 1 boiler.

*Semi-dry FGD (LSD):* CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water, as detailed in Table 12. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[9]

**Table 12: LSD Water Requirements**

| Unit | Water required for LSD (gpm) | Water required for LSD (Mg/year) |
|---|---|---|
| Drake 6 | 68 | 35.7 |
| Drake 7 | 100 | 53.0 |
| Nixon 1 (scaled) | ~160 | ~84.0 |

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

*DSI:* CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[10] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality

[9] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[10] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon Unit 1 in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

**Table 13: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Unit(s) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|
| | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr $SO_2$ rates | 1 | RMNP | 17 | --- | --- | 6 | --- | --- |
| DSI @ 0.18 lb/MMBtu | 1 | | 17 | 6 | 11 | 6 | 1 | 5 |
| LSD @ 0.10 lb/MMBtu | 1 | | 17 | 6 | 11 | 6 | 1 | 5 |
| LSD @ 0.08 lb/MMBtu | 1 | | 17 | 6 | 11 | 6 | 1 | 5 |

**Table 14: Visibility Results – SO2 Control Scenarios**

| SO2 Control Scenario | Unit(s) | Output (@ 98$^{th}$ Percentile Impact)* | 98$^{th}$ Percentile Impact Improvement | 98$^{th}$ Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|
| | | (deciviews) | (deciviews) | (%) | ($/deciview) |
| Max 24-hr $SO_2$ rates | 1 | 0.914 | | | --- |
| DSI @ 0.18 lb/MMBtu | 1 | 0.48 | 0.44 | 48% | $11,249,869 |

| | | | | | |
|---|---|---|---|---|---|
| LSD @ 0.10 lb/MMBtu | 1 | 0.46* | 0.46 | 50% | $26,454,076 |
| LSD @ 0.070 lb/MMBtu | 1 | 0.42 | 0.50 | 55% | $28,307,522 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Nixon Modeling Summary" for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi-dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% $SO_2$ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton $SO_2$ removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

### *b. Filterable Particulate Matter (PM) & Particulate Matter ($PM_{10}$)*

Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/$PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP106 Condition 1.5.5 requires Unit 1 to conduct performance testing for $PM_{10}$ annually. While the emission limit in Condition 1.5.1 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 15 shows the most recent stack test data (April 14, 2008). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

**Table 15: Nixon Unit 1 2008 Stack Test Results**

| Pollutant | Unit 1 (lb/MMBtu) |
|---|---|
| Filterable $PM_{10}$ | 0.0021 |
| $PM_{10}$ Control efficiency | 99.5% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control options. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limits are RP for $PM/PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for $PM/PM_{10}$ is not needed for Nixon Unit 1.

***c. Nitrogen Oxides ($NO_x$)***

**Step 1: Identify All Available Technologies**

CSU identified four $NO_x$ control options:

Overfire air (OFA)
Ultra-low $NO_x$ burners (ULNBs)
Selective Catalytic Reduction (SCR)
Ultra-low $NO_x$ burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Ultra-low $NO_x$ burners and Over-fire air (ULNBs+OFA)
Selective Non-Catalytic Reduction (SNCR)
Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[11]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater $NO_x$ reduction for Unit 1. Since ROFA® technology would not be expected to

[11] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

**Step 2: Eliminate Technically Infeasible Options**

***OFA:*** Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low $NO_x$ burners, such as those already present on Unit 1. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of $N_2$ rather than $NO_x$. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel $NO_x$ are formed[12]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal $NO_x$. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Unit 1.

***ULNBs:*** Unit 1 has low $NO_x$ burners installed, shown in Table 2. These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased $NO_x$ emission reductions with these ultra-low $NO_x$ burners. ULNBs are a technically feasible option for Unit 1.

*ULNBs+OFA:* Since ULNBs and OFA are each technically feasible options and would be installed separately for Unit 1, it stands to reason that ULNBs+OFA is a technically feasible options for Unit 1.

*SCR*: SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

[12] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for $NO_x$ control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

While lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for CSU Nixon, a retrofit SCR, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 1 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Nixon Unit 1.

***ULNBs/SCR layered:*** A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Nixon Unit 1.This scenario considers that less $NO_x$ would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for Nixon Unit 1.

***ECO®:*** The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[13] and thus, is considered technically infeasible.

***RRI:*** Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[14] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Nixon Unit 1.

***SNCR:*** Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have

[13] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[14] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's RP analysis because CSU asserts that SNCR achieves full-load $NO_x$ removal in the same range as ULNB at a higher levelized cost ($/ton $NO_x$ removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule, and therefore should be ruled out for RP as well. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal $NO_x$ removal, resulting in $NO_x$ removal declines. The weighted average $NO_x$ removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a technically feasible alternative for Nixon Unit 1. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a $NO_x$ control option for EGUs, so the Division included SNCR in the full four-factor analysis.

***Coal Reburn + SNCR:*** Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[15]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[16] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nixon Unit 1 to determine control efficiencies and annual reductions.

*OFA:* CSU estimated that overfire air, in conjunction with the existing low-$NO_x$ burners, is capable of reducing $NO_x$ emissions approximately an additional 25% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-$NO_x$ burners controlling 35 – 55% and LNB with

[15] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[16] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

OFA controlling 40 – 60% of $NO_x$ emissions.[17] The low $NO_x$ burners currently achieve about 10% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low $NO_x$ burners.[18] Therefore, the Division concurs with CSU's additional 25% $NO_x$ control estimate.

*ULNBs*: CSU asserts that additional $NO_x$ reductions of 20% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at Nixon Unit 1. These additional $NO_x$ reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled $NO_x$ emissions, which is consistent with a U.S. Department of Energy Study which estimated $NO_x$ emissions reductions between 75 – 85%.[19] Therefore, the Division concurs with CSU $NO_x$ reduction estimates for ULNBs.

*ULNBs+OFA*: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. ULNBs alone can achieve 20% control; OFA alone can achieve 25% control. When determining the appropriate control efficiency regarding the combination of ULNBs and OFA, the most important consideration to note is that Nixon burns only Power River Basin (PRB) coal which is low in nitrogen content initially, so the margin to reduce $NO_x$ is lower than other facilities (i.e. Drake). The Division and CSU concur that a realistic control efficiency assumption is 30% for Nixon Unit 1.

*SNCR:* Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[20] to conservatively approximate that Nixon Unit 1 can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% $NO_x$ reduction using 2008 baseline emissions (or 0.05 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions and adjusted the resultant SCR percent removal to 73% (or 0.07 lb/MMBtu), which the Division considers more realistic and consistent with other Colorado facility submittals. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80

[17] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[18] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

[19] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory. http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf

[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

– 90% reduction.[21,22] However, in the Division's experience a emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

*ULNBs/SCR layered approach:* CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce $NO_x$ entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same $NO_x$ emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 16 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 16: Nixon Unit 1 7 $NO_x$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners (LNB) | ~10% | Y – installed |
| LNB + OFA | 60 – 81% | Y (partially installed) |
| Overfire air (OFA) | 10 – 25% (alone) | Y |
| Ultra-low $NO_x$ burners (ULNBs) | 20% | Y |
| ULNBs+OFA | 30% | Y |
| Selective non-catalytic reduction (SNCR) | 20 – 40% | Y |
| Selective catalytic reduction (SCR) | 70 – 90% | Y |
| ULNB/SCR layered approach | 70 – 90% | Y |
| ECO® | n/a | N |
| RRI | n/a | N |
| Coal reburn +SNCR | n/a | N |

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

*OFA:* Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake and Nixon boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "$NO_x$

[21] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Controls for Existing Utility Boilers,"[23] OFA alone ranges from $410 - $1,100 per ton $NO_x$ reduced annually for units estimating 15 – 30% $NO_x$ control, which is within the range of Nixon's estimated OFA $NO_x$ reductions (25%). The estimates in Table 17 and Table 18 are within this range. Therefore, the Division concurs with the OFA cost estimates.

*ULNBs*: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 18. The Division considers CSU's estimated costs more than reasonable, with ULNBs at about $1,200/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[24, 25]
*ULNB+OFA*: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

*SNCR:* A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[27] Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[28]

[23] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[24] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/**nox**-2000.pdf
[25] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[26] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[27] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.
[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The Division used information from a similar facility submittal to determine approximate SNCR costs scaled for the Nixon boiler since CSU did not have SNCR information.[29] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Nixon boiler in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 1 is approximately $4,500 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[30,31] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[32] Although the resulting cost estimates for the Nixon boiler greater than these ranges, the smaller size of the boiler as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

*SCR:* CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving $NO_x$ emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[33,34] The SCR system estimates for the CSU Nixon boiler is approximately $6,400, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

*ULNBs/SCR layered approach:* CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 17 illustrates resultant $NO_x$ emissions for each technically feasible control option. Table 18 shows the $NO_x$ control costs for each unit based on detailed cost analyses. The Division estimated resultant $NO_x$ using annual average reductions for

[29] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.
[30] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[31] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[32] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[33] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[34] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

tons of $NO_x$ reduced per year. The Division's experience with power plants suggest that the maximum 30-day rolling average $NO_x$ emission rate is 5-15% higher than the annual average emission rate.

**Table 17: Unit 1 Control Resultant NOx Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Unit 1 | | |
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day rolling (lb/MMBtu) |
| Baseline | --- | 2,357 | 0.258 | |
| Ultra-low NOx burners (ULNBs) | 20 | 1,885 | 0.206 | 0.24 |
| Overfire air (OFA) | 25 | 1,768 | 0.194 | 0.22 |
| ULNBs+OFA | 30 | 1,650 | 0.181 | 0.21 |
| Selective Non-Catalytic Reduction (SNCR) | 30 | 1,650 | 0.181 | 0.21 |
| ULNB+SCR | 73 | 636 | 0.070 | 0.080 |
| Selective Catalytic Reduction (SCR) | 73 | 636 | 0.070 | 0.080 |

**Table 18: Unit 1 NOx Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Ultra-low NOx burners (ULNBs) | 471 | $567,000 | $1,203 | $1,203 |
| Overfire air (OFA) | 589 | $403,000 | $684 | ($1,392) |
| ULNBs+OFA | 707 | $907,000 | $1,372 | $4,812 |
| Selective Non-Catalytic Reduction (SNCR) | 707 | $3,226,877 | $4,564 | --- |
| ULNB+SCR | 1,720.4 | $11,007,000 | $6,398 | $7,677 |
| Selective Catalytic Reduction (SCR) | 1,720 | $11,010,000 | $6,400 | --- |

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[35], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and

[35] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14

shutdown, after SIP approval, it would take CSU be approximately 2-3 years for SNCR and 3-4 years for SCR. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

*OFA:* Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

*ULNBs:* The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

*SNCR /SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a aqueous ammonia reagent versus an ammonia reagent.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon 1 is in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

**Table 19: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Unit(s) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|
| | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour NOx rates | 1 | RMNP | 17 | --- | --- | 6 | --- | --- |
| ULNBs @ 0.21 lb/MMBtu | 1 | | 17 | 15 | 2 | 6 | 4 | 2 |
| OFA @ 0.19 lb/MMBtu | 1 | | 17 | 15 | 2 | 6 | 4 | 2 |
| ULNBs+OFA @ 0.18 lb/MMBtu | 1 | | 17 | 15 | 2 | 6 | 4 | 2 |
| SNCR @ 0.18 lb/MMBtu | 1 | | 17 | 15 | 2 | 6 | 4 | 2 |
| SCR @ 0.07 lb/MMBtu | 1 | | 17 | 12 | 5 | 6 | 3 | 3 |

**Table 20: Visibility Results - NOx Control Scenarios**

| NOx Control Scenario | Unit(s) | Output (@ 98th Percentile Impact)* | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|
| | | (deciviews) | (deciviews) | (%) | ($/deciview) |
| Max 24-hour NOx rates | 1 | 0.91 | --- | --- | --- |
| ULNBs @ 0.21 lb/MMBtu | 1 | 0.77 | 0.15 | 16% | $3,831,081 |
| OFA @ 0.19 lb/MMBtu | 1 | 0.76* | 0.15 | 17% | $2,616,883 |

| | | | | | |
|---|---|---|---|---|---|
| ULNBs+OFA @ 0.18 lb/MMBtu | 1 | 0.75* | 0.16 | 18% | $6,024,845 |
| SNCR @ 0.18 lb/MMBtu | 1 | 0.75* | 0.16 | 18% | $20,042,714 |
| SCR @ 0.07 lb/MMBtu | 1 | 0.68 | 0.24 | 26% | $46,639,831 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Nixon Modeling Summary" for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Nixon Unit 1 the following NOx emission rate:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that ultra-low NOx burners with over-fire air is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

V. RP Evaluation for Fugitive Dust Sources: Coal Reclaim Conveyor (003) and Coal Handling (008)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 95OPEP106.

Coal handling is comprised of five (6) parts – reclaim tunnel bagfilter vent, coal crusher building bagfilter vent, coal gallery bagfilter vents, and coal train off-loading-conveying-stockpiling. It should be noted that while these two sources are reported individually in Colorado's emission inventory, in the Operating Permit, these sources are combined together since coal handling is treated as one point. Colorado Regulation No.1.II.A.1 limits opacity from these sources to 20%. This source is also subject to NSPS Subpart Y, New Source Performance Standards for Coal Preparation Plants. Additionally, the following measures to control fugitive dust via a fugitive particulate emissions control plan (Condition 3.4):

- A wet dust suppression system shall be used for railroad car unloading.
- Above ground conveyors to and from the transfer building must be covered.
- Loadout to storage must by telescoping chute.
- Emissions from coal storage piles shall be effectively controlled by application of chemical binders and by watering, if need be.

These existing controls and corresponding emission limits in Section II, Condition 3 of Operating Permit 95OPEP106 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options**
**For**
**Tri-State Generation & Transmission Association, Inc. – Nucla Station**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Tri-State Generation & Transmission Association, Inc. |
| Source Type: | Electric Utility Steam Generating Unit |
| SCC (EGU): | 10100218 |
| Boiler Type: | Atmospheric Circulating Fluidized Bed |

The Tri-State Generation Transmission & Association, Inc. (Tri-State) Nucla Station is located in Montrose County approximately 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and limestone injection into the fluidized bed for the removal of sulfur dioxide ($SO_2$). The boiler is designed for the reduction of $NO_x$ formation and a small Selective Non-Catalytic Reduction (SNCR) system using anhydrous ammonia injection is used for $NO_x$ trim to ensure compliance with annual $NO_x$ limits. Additionally, the facility includes a number of fugitive dust sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nucla facility, and information about similar facilities to determine RP for PM and $SO_2$. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1]."

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

These *de minimis* levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

The Nucla facility originally consisted of three coal fired stoker boilers that were shut down and replaced with an atmospheric circulating fluidized bed (CFB) boiler (Unit #4). Unit #4 was placed in service in June, 1987. CFBs without post-combustion controls are able to achieve emission rates of $NO_x$ and $SO_2$ that are lower than Pulverized Coal (PC) fired boilers due to the nature of their design (lower combustion temperatures result in less $NO_x$ formation, while intimate mixing of a sorbent within the fluidized bed results in enhanced $SO_2$ removal). $SO_2$ emissions from CFBs without post-combustion controls are typically lower than similarly sized PC-fired boilers equipped with Flue Gas Desulfurization (FGD) systems.[2] The original construction of Unit #4 included four baghouses for the control of $PM_{10}$ emissions, limestone injection to the combustion chamber for $SO_2$ removal, and inherent minimization of $NO_x$ emissions due to boiler design.

In 2006, Tri-State permitted and installed a small-scale SNCR system that injects anhydrous ammonia to provide additional $NO_x$ reduction. Tri-State does not operate the SNCR system frequently; it is used on occasions when $NO_x$ emissions approach 0.4 lb/MMBtu (operation above this level at high unit capacity factors results in levels that approach the annual $NO_x$ limit of 1,987.9 tons per year on a 12-month rolling basis). The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour.[3]

Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, and July 30, 2010. Table 1 depicts technical information for Unit 4 at Nucla Station.

**Table 1: Nucla Unit 4 Technical Information**

| | Unit 4 |
|---|---|
| Placed in Service | 1987 |
| Gross Boiler Rating, MMBtu/Hr for coal | 1,112 |
| Electrical Power Rating, Net Megawatts | 110 |
| Description | Pyropower Circulating Fluidized Bed, Coal Fired Boiler |

[2] Babcock & Wilcox Company, 2000. "Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power" Presented to POWER-GEN Asia 2000. Page 2.
[3] Tri-State, May 14, 2010. "RE: Response to the Division's January 25, 2010 Letter Regarding $NO_x$ Emissions Control Costs." Page 6.

| | |
|---|---|
| Air Pollution Control Equipment | $PM/PM_{10}$ –Fabric Filter Baghouses (1987)<br>$NO_x$ – Voluntary SNCR (2006)<br>$SO_2$ – Limestone Injection (1987) |
| Emissions Reduction (%) | NOx – NA[4]<br>$SO_2$ – 77.4%<br>$PM/PM_{10}$ – 98% - 99.9+%[5] |

## II. Source Emissions

Table 2 summarizes the $NO_x$ and $SO_2$ actual emissions averaged over the 2006 – 2008 timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices (APENs) submitted by the facility (based on amount and heat content and amount of coal combusted, also as reported on the APENs).

**Table 2. Summary of 2006 - 2008 Averaged Emissions – Tri-State Nucla Station**

| $NO_x$ (tons/year) | $SO_2$ (tons/year) | $PM_{10}$ (tons/year) |
|---|---|---|
| 1,760 | 1,335 | 40 |

**Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Tri-State Nucla Station**

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| Unit 4 Boiler | $SO_2$ (tons) | 1509.4 | 1230.4 | 1265.7 | 1335.2 |
| | $SO_2$ (lb/MMBtu) | 0.34 | 0.30 | 0.30 | 0.31 |
| | $NO_x$ (tons) | 1716.0 | 1598.0 | 1711.4 | 1675.1 |
| | $NO_x$ (lb/MMBtu) | 0.39 | 0.38 | 0.40 | 0.39 |
| | $PM_{10}$ (tons) | 41.6 | 39.4 | 40.24 | 40.4 |
| | $PM_{10}$ (lb/ MMBtu) | 0.009 | 0.009 | 0.009 | 0.009 |
| *Coal Handling & Processing* | *$PM_{10}$ (tons)* | *2.09* | *2.15* | *2.15* | *2.13* |
| *Ash Handling & Processing* | *$PM_{10}$ (tons)* | *8.91* | *10.62* | *10.62* | *10.05* |
| P401 Cooling Tower | $PM_{10}$ (tons) | 37.5 | 23.7 | 0.34 | 20.5 |
| *P402 Cooling Tower* | *$PM_{10}$ (tons)* | *9.8* | *9.8* | *9.8* | *9.8* |
| *Limestone Preparation* | *$PM_{10}$ (tons)* | *1.29* | *1.29* | *1.29* | *1.29* |

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

[4] $NO_x$ emission reductions from the existing SNCR system have not been characterized because the system is operated only infrequently – total reported emissions are therefore assumed to be uncontrolled.

[5] The low range is calculated assuming uncontrolled emissions based on AP-42 factors. The high range is stated in the U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf. Page 5.

Note also that Tri-State installed improved drift eliminators on the P401 Cooling Tower in 2007. The Operating Permit[6] for the facility includes a limit of 0.55 tons $PM_{10}$ per year effective beginning October 1, 2007 (actual emissions for 2008 were reported to be 0.34 tons per year); therefore this unit will also not be considered further in this analysis.

The Title V permit includes the following limits for the Unit 4 Boiler:

- $NO_x$: 0.50 lbs/MMBtu on a rolling 30-day average (PSD limit), 0.5 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da) and 1987.9 tons per year on a rolling 12-month total
- $SO_2$: 1.2 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da), 1.2 lb/MMBtu on a 3-hr average (Colorado Regulation No. 1), 0.4 lb/MMBtu on a 30-day average (Colorado Regulation No. 6) and 1598.9 tons per year on a rolling 12-month total; 70% reduction at less than 0.6 lb/MMBtu (30-day rolling average)
- $PM_{10}$: 131 tons per year on a rolling 12-month total
- PM: 0.03 lb/MMBtu (PSD limit), 0.03 lb/MMBtu (NSPS Subpart Da) 0.1 lb/MMBtu (Colorado Regulation No. 1) and 135.9 tons per year on a rolling 12-month total

## III. Units Evaluated for Control

The Nucla boiler burns Colorado bituminous coal. Nucla Station is a mine-mouth facility; therefore the Division assumes that this facility burns New Horizon Coal, since that facility is the closest coal mine identifiable in Division records. The actual APEN coal specifications (2006 – 2008) are listed below in Table 4. Uncontrolled emission factors are outlined in Table 5.

**Table 4: Coal Specifications (2006 - 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| Nucla Unit 4 | 10,545 | 0.83 | 19.95 |

**Table 5: Uncontrolled emission factors for Nucla RP-eligible sources[7]**

| | Pollutant | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Unit 4 (lb/ton) | 5.0 | 25.8 | 17.0 | 12.4 |
| Unit 4 (lb/MMBtu) | 0.24 | 1.22 | 0.81 | 0.59 |

[6] Colorado Air Pollution Control Division, September 25, 2007. Colorado Operating Permit 96OPMO168: Nucla Station. Section II: Condition 8.2, Page 38.

[7] PM and $PM_{10}$ emission factors are from AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf (for spreader stokers with multiple cyclones and reinjection). Uncontrolled $SO_2$ emission factors are based on the AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1 emission factor for underfeed stoker boilers (Table 1.1-3). Uncontrolled $NO_x$ emission factors are based on actual emissions from 2006 – 2008.

IV. Reasonable Progress Evaluation of Unit 4

***a. Sulfur Dioxide***

**Step 1: Identify All Available Technologies**

The Division identified all of the available CFB control technologies listed below.

*Fuel Switching – Natural Gas or Alternate Coal Source*
*Fuel Washing*
*Limestone Injection Process Upgrades*
*Post-Combustion Controls: Dry Scrubbing (Spray Dry Absorber, Circulating Dry Scrubber, Hydrated Ash Reinjection and Dry Sorbent Injection)*
*Post-Combustion Controls: Wet Scrubbing*

As discussed in EPA's BART Guidelines[8], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the existing limestone injection process if technically feasible.

The current PSD permit $SO_2$ limits are depicted in Table 6.

**Table 6: Nucla Unit 4 $SO_2$ PSD Permit Limits**

| | $SO_2$ limits (lb/MMBtu) | | | Rolling 12-month Emission Limit (tons/year) |
|---|---|---|---|---|
| | 3-hour avg. (Colo. Reg. No. 1) | Rolling 30-day avg. (NSPS Subpart Da) | 30-day avg. (Colo. Reg. No. 6) | |
| Unit 4 | 1.2 | 1.2 | 0.4 | 1,599 |

**Step 2: Eliminate Technically Infeasible Options**

***Fuel Switching – Natural Gas or Alternative Coal Sources:*** CFB boilers are designed to create a circulating bed of solid fuels; the nature and locations of the solids and air injection points as well as the combustion zone itself are inherently different from traditional PC and natural gas-fired boilers. The recent conversion from a natural gas-fired boiler to a CFB-boiler at the Lamar Light and Power facility in Lamar, Colorado required the construction of an entirely new and separate unit. Therefore, the Division determines that the conversion to natural gas is technically infeasible for Nucla's CFB boiler.

Nucla Unit #4 is currently burning coal from the New Horizon Mine located five miles south of the plant, with an average sulfur content of 0.83%. The facility is located approximately 4.5 miles southeast of Nucla, Colorado and does not have rail service. There are no other coal mines located 100 miles of the facility. Because the current coal source is already lower than 1% sulfur and no other sources within a reasonable distance of the facility have been identified, fuel switching to other coal types will not be considered further in this analysis.

[8] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs 39133.

***Fuel Washing:*** Fuel washing has been used historically to reduce the sulfur content of some high sulfur coals prior to combustion. There are no identified fuel-washing processes for low sulfur coal.

***Existing Process Upgrades and Post-Combustion Controls***: In the absence of any specific feasibility or cost information related to $SO_2$ controls for the Nucla Station, the Division relied on control evaluations performed for other CFB boilers, with a focus on CFB boilers in the western part of the country. Coal supplies for CFB boilers in the eastern part of the country are significantly different from western coals in terms of sulfur and heat content; therefore the Division believes that the specifics of control devices for eastern CFB boilers may not be wholly applicable to Nucla Unit 4. The majority of recent BACT determinations identify limestone injection, with or without additional post-combustion controls as the chosen $SO_2$ control device. Refer to "Division RBLC Analysis" for more details. The Division reviewed two of the most recent BACT analysis reports in detail: the lignite-fired Spiritwood Station in North Dakota[9] and the waste coal-fired Bonanza Station in Utah[10]. The Spiritwood Station was intended to fire beneficiated lignite but is designed with the capability for firing dried lignite and subbituminous coal as well, and the BACT analysis specifically identified the findings to be applicable to subbituminous coal. The estimated control efficiencies and costs from these reports were used as a basis to evaluate potential $SO_2$ emission control options at Nucla.

***Limestone Injection Process Upgrades***: The average reduction in $SO_2$ emissions due to limestone injection into the CFB boiler for the baseline period is estimated to be 77.4% as shown in Table 1, above. The unit participated in a U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) from 1988 – 1991 in order to examine the energy and environmental impacts from the unit, which was the first utility-scale atmospheric CFB boiler at the time. The project demonstrated a 70% $SO_2$ removal rate at a calcium to sulfur ratio (Ca/S) of 1.5 and a 95% removal rate at a calcium to sulfur ratio of 4.0[11]. The demonstration project tested a range of western bituminous coals, including Salt Creek (0.5% sulfur), Peabody (0.7% sulfur) and Dorchester (1.5% Sulfur), with the Salt Creek coal serving as the baseline coal (used in 62 of the 72 tests). Limestone injection process upgrades are feasible for Nucla Unit 4.

***Post-Combustion Controls – Dry Scrubbing:*** Additional treatment of the boiler exhaust gases can potentially be accomplished with several dry scrubbing techniques.

[9] Barr, July 2007. "Application for a Permit to Construct a Combined Heat and Power (CHP) Plant." Prepared for Great River Energy – Spiritwood Station, Spiritwood, ND.
[10] EPA, August 30, 2007. "Deseret Power Electric Cooperative, Bonanza Power Plant, Waste Coal Fired Unit: Prevention of Significant Deterioration Permit to Construct – Final Statement of Basis for Permit No. PSD-00-0002.01.00. "
[11] U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf

*Spray Dryer Absorption (SDA)* is the most commonly used follow-on controls for CFB boilers with limestone injection. SDAs currently make up about 12% of Flue Gas Desulfurization (FGD) systems at U.S. power plants[12]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system captures $SO_2$ by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and the collected in a particulate control device. A SDA system is technically feasible for Nucla Unit 4.

*Circulating Dry Scrubber (CDS) Systems* use a circulating fluidized bed of dry hydrated lime in a separate reactor tower. The flue gas must first be humidified with a water mist. EPA noted in the Bonanza BACT analysis that CDS systems have limited application on large PC-fired boilers or CFB boilers, and can result in particulate loading rates that are high enough to create unacceptable pressure drops across fabric filters and therefore require electrostatic precipitators for particulate control.[13] The potential need to replace the existing baghouse (99.9% particulate control) with an electrostatic precipitator renders a CDS system inappropriate as an option for the Nucla station.

*Hydrated Ash Reinjection (HAR)* increases utilization of uncreated calcium oxide in the CFB boiler ash by collecting, hydrating and re-introducing a portion of the unit's ash in a separate vessel prior to the baghouse. HAR is technically feasible for Nucla Unit 4.

*Dry Sorbent Injection (DSI)* systems require injection of powdered absorbent directly into the flue gas stream. EPA identified this option as impractical for use in a CFB boiler burning low sulfur coals due to an expected $SO_2$ reduction of less than 50%.[14] DSI is a technically feasible option for Nucla.

***Post-Combustion Controls – Wet Scrubbing:*** Wet Flue Gas Desulfurization (FGD) systems were identified as potentially feasible for CFB boilers in both the Bonanza and Spiritwood BACT analyses. The process involves an alkaline slurry (lime or limestone) scrubbing liquid in an absorber tower. The process produces a wet byproduct that requires dewatering. Wet scrubbing is a technically feasible option for Nucla Unit 4.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

***Limestone Injection Process Upgrades:*** The Spiritwood BACT analysis states that the control efficiency from the limestone injection process is expected to be 75%[15] (further reductions occur in a Spray Dry Absorber). EPA acknowledges in the Bonanza BACT analysis report that a control efficiency of 80 – 85% should be expected for the limestone injection process alone[16].

[12] Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environment Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg V.
[13] Ibid., Page 92.
[14] EPA, Deseret Power Electric Cooperative…Page 93.
[15] Barr, Appendix E, Page 50
[16] EPA, Deseret Power Electric Cooperative…Page 99.

The Division believes that an expectation of 95% reduction for the Nucla station from the limestone injection process, although it may have been demonstrated during the CCTDP test project, is not appropriate as a long term operation scenario. The fluidized bed is currently optimized carefully to balance efficiency, operational and emission characteristics. Increasing the Ca/S to 4.0 in order to achieve 95% $SO_2$ reduction is expected to cause significant operational issues; the Division has not found any evidence of current CFB boilers in operation with Ca/S ratios near 4.0. Higher limestone injections will also result in an increase in $NO_x$ emissions, although the quantitative relationship is not well understood.[17] For these reasons, the Division believes that an increase in $SO_2$ control efficiency to 85% by increasing limestone injection is a feasible option. This correlates to an approximate 39.4% decrease in comparison to current $SO_2$ emissions.

***Spray Dry Absorber:*** Based on experience with other Colorado EGUs, the Division believes that a realistic achievable control efficiency for a SDA at Nucla is approximately 87%, or an approximate 0.04 lb/MMBtu (30-day rolling average). This is approximately 97% from uncontrolled $SO_2$ emissions. A review of the EPA's RBLC database showed two retrofit Western facilities from about 0.04 – 0.05 lb/MMBtu (30-day rolling average) with SDAs as the $SO_2$ control option. Please refer to the document "RBLC for CFBs – July 2010" for more information.

***Limestone Injection Improvements + Spray Dry Absorber:*** Limestone injection improvements (85%) combined with a spray dry absorber (90%) could achieve up to approximately 94% control from current $SO_2$ emissions, or 98.4% from uncontrolled $SO_2$ emissions.

***Hydrated Ash Reinjection:*** EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion $SO_2$ emissions by about 80%.[18] This results in about 95% reduction from uncontrolled $SO_2$ emissions.

***Hydrated Ash Reinjection + Limestone Injection Improvements:*** It may be possible to combine HAR (80% reduction) with improvements to the limestone injection system (85% reduction). This results in a potential 87.9% decrease from current $SO_2$ emissions or 96.9% reduction from uncontrolled $SO_2$ emissions.

***Post-Combustion Controls – Wet Scrubbing:*** EPA noted a potential $SO_2$ removal efficiency of 94% for the post-combustion gas in the Bonanza BACT analysis[19]. Combined with the current limestone injection system, the overall potential control efficiency is 98.4% from uncontrolled $SO_2$ emissions.

[17] Ibid., Page 100.
[18] Barr, Appendix E, Page 93.
[19] Ibid., Page 94.

Table 7 summarizes each available technology option and technical feasibility for $SO_2$ control for Nucla Unit 4.

**Table 7: Nucla Unit 4 SO2 Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Fuel switching – Natural gas or alternate coal source | Natural gas: 99%<br>Alternate coal: minimal | Natural gas – N<br>Alternate coal – Y – will not provide further SO2 control |
| Fuel washing | Minimal | N |
| Limestone Injection Process Upgrades | ~85% overall control efficiency<br>~40% increase from current control efficiency | Y |
| Dry Scrubbing (SDA) | ~97% overall control efficiency<br>~87% increase from current control efficiency | Y |
| Limestone Injection Improvements + SDA | ~98% overall control efficiency<br>~94% increase from current control efficiency | Y |
| Circulating Dry Scrubber | Unknown | N |
| Hydrated Ash Reinjection (HAR) | ~95% overall control efficiency<br>~80% increase from current control efficiency | Y |
| HAR + Limestone Injection Improvements | ~97% overall control efficiency<br>~88% increase from current control efficiency | Y |
| Dry Sorbent Injection (DSI) | <50% overall control efficiency | Y – will not provide further SO2 control |
| Wet Scrubbing | ~98% overall control efficiency<br>~94% increase from current control efficiency | Y |

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

Costs for $SO_2$ control options were evaluated based on analyses for similar systems proposed at other western CFB boiler units (Spiritwood and Bonanza). Refer to "Nucla APCD Cost Analysis" for more details. Depending on the control option, the Division also relied on additional submittals regarding Nucla feasibility and costs submitted on

*Limestone Injection Process Upgrades:* The Division relied on the U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) study to determine control efficiency for limestone injection upgrades. The Spiritwood BACT analysis used the cost of limestone in 2006 to determine limestone injection costs. The Division adjusted this cost using the Consumer Price Index (CPI), increasing limestone cost from $80 per ton to $87 per ton. The Division also calculated the additional amount of limestone (in tons per year) that will be needed to achieve an 85% control efficiency (or 40% increase from current control efficiency). These calculations result in an annualized cost of $914,920 per year. Refer to "Nucla APCD Cost Analysis" for more details.

*Dry Scrubbing (Spray Dry Absorber)/ Limestone Injection Process Upgrades + SDA:* The Division again relied on the Spiritwood BACT Analysis to determine the cost of a spray dry absorber (SDA) system. The annualized cost (2006) for the Spiritwood CFB was $2,644,412. The Division used the CPI to adjust this cost to $2,814,108 and then scaled this cost up by the ratio of potential tons $SO_2$ removed at the Nucla CFB compared to tons removed at the Spiritwood CFB, and then added in a retrofit factor of 50% to consider the difficulty of the retrofit at Nucla as compared to a new CFB (Spiritwood). This results in an annualized cost of $4,304,807. For limestone injection improvements combined with a SDA system, the Division combined annualized costs from both controls to result in an annualized cost of $5,219,097. Refer to "Nucla APCD Cost Analysis" for more details.

*Wet Scrubbing:* Although Wet FGD systems provide higher levels of $SO_2$ removal over dry scrubbers, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using a wet scrubber versus the spray dry absorber is identified as $12,902/ton in the Spiritwood BACT analysis[20], and $10,540 per ton in the Bonanza BACT analysis.[21] A wet scrubber at the Nucla Station should be expected to have even higher costs than these examples due to the retrofit factor. Therefore, a Wet FGD option will not be considered further in this analysis.

*HAR/HAR+Limestone Injection Improvements:* Study-level information for potential HAR systems at Nucla or any other EGU in the western part of the country were not available for use in evaluating costs. Therefore, the Division does not consider this option to commercially available at this time, and HAR will not be considered further in this analysis. However, HAR is technically feasible and will be considered in future analyses if more information becomes available.

Table 8 illustrates resultant $SO_2$ emissions for each technically feasible control option. Table 9 shows the $SO_2$ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 3. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average $SO_2$ emission rate is approximately 5% higher than the annual average emission rate.

[20] Barr, Appendix E, Page 95.
[21] EPA, Deseret Power Electric Cooperative…Page 95.

**Table 8: Nucla Unit 4 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Unit 4 | | |
| | | (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,335 | 0.299 | 0.314 |
| Limestone Injection Improvements (LII) | 39.4 | 809 | 0.182 | 0.191 |
| Hydrated Ash Reinjection (HAR) | 80.0 | 267 | 0.060 | 0.063 |
| Spray Dry Absorber (SDA) | 87.0 | 174 | 0.039 | 0.041 |
| HAR + LII | 87.9 | 162 | 0.036 | 0.038 |
| | | | | |
| LII+SDA | 93.9 | 81 | 0.018 | 0.019 |
| Wet Scrubbing | 94.0 | 80 | 0.018 | 0.019 |

**Table 9: Nucla Unit 4 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| LII | 526 | $2,188,595 | $4,161 | $4,161 |
| HAR | 1,068 | Not determined | | |
| HAR+LII | 1,173 | Not determined | | |
| SDA | 1,162 | $7,604,627 | $6,547 | $8,520 |
| LII+SDA | 1,254 | $9,793,222 | $7,808 | $23,619 |
| Wet Scrubbing | 1,255 | Not determined | | |

Factor 2: Time Necessary for Compliance

It is assumed that the Limestone Injection Improvements will not require any construction or capital improvements since the Unit has already been demonstrated at the higher Ca/S ratios during the CCTDP test project.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 – 5 years to implement the SDA or LII+SDA control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

There are no identified energy or non-air quality impacts associated with improvements to the Limestone Injection System. Thus, this factor does not influence the selection of this control.

*Wet Scrubbing:* Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP $SO_2$ control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of $SO_2$ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in $SO_2$ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental $SO_2$ emission reduction benefits (tons of $SO_2$ reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when compared to a SDA system when applied to the Nucla Unit 4 CFB boiler.

*Spray dry absorber (SDA):* Other Colorado facility have noted that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[22]

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

*DSI:* Other Colorado facility have documented additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[23] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

[22] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[23] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Factor 5 (optional): Evaluate Visibility Results
Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

**Step 6: Select RP Determination**

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein, the state has determined that the existing permitted $SO_2$ emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

***b. Filterable Particulate Matter (PM) & Particulate Matter ($PM_{10}$)***

Nucla Unit 4 is currently equipped with a four baghouse system to control PM/$PM_{10}$ emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

The baghouses performed over the 2006 – 2008 baseline period with PM and $PM_{10}$ emissions of 0.013 lb/MMBtu and 0.009 lb/MMBtu, respectively. During the CCTDP test project, the unit demonstrated particulate emissions ranging between 0.0072 to 0.0125 lb/MMBtu, corresponding to a removal efficiency of 99.9%[24]. This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel.

[24] U.S. Department of Energy, Page 5.

A Division review of the $PM/PM_{10}$ emission limits in the current Title V permit revealed that these limits are for filterable $PM/PM_{10}$ emissions only.

Table 10 shows the most recent *verified* stack test data (2002). Another stack test was conducted in August 2010, but is not yet available for release due to ongoing analysis by the Division and Tri-State. Real-time data demonstrates that these baghouses are meeting >95% control. The Operating Permit (96OPMO168) limit is 0.03 lb/MMBtu for $PM/PM_{10}$ emissions (Conditions 1.1.1, 1.1.2). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

**Table 10: Nucla Unit 4 Stack Test Results (August 2002)**

| Pollutant | Unit 4 (lb/MMBtu) |
|---|---|
| Filterable $PM_{10}$ | 0.014 |
| $PM_{10}$ Control efficiency | 98.3% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is in the range of recent BACT determinations. Please refer to "Division RBLC Analysis" for more details about recent BACT determinations.

The State has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for $PM/PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Therefore, a full 4-factor analysis is not needed to evaluate $PM/PM_{10}$ for the Unit 4 boiler.

### *c. Nitrogen Oxides ($NO_x$)*

**Step 1: Identify All Available Technologies**

*Fuel Switching – Natural Gas or Alternate Coal Source*
*Selective Non-Catalytic Reduction (SNCR) system upgrades*
*Selective Catalytic Reduction (SCR) with flue gas reheat*

**Step 2: Eliminate Technically Infeasible Options**

Tri-State provided an analysis of the requirements and costs associated with increasing the size of the existing SNCR system to allow for more frequent operation, and the Division has relied on this information (with some exceptions) in order to evaluate a full-time SNCR option. Due to lack of any specific feasibility or cost information related to SCR controls at Nucla Station, the Division relied on recent control evaluations performed for other CFB boilers in the western part of the country (the Spiritwood and Bonanza evaluations, noted in Section III.a. above).

Every BACT determination listed in the RACT/BACT/LAER Clearinghouse for CFB Boilers specifies SNCR; no SCR determinations or installations have been identified. This is likely due to the significantly high incremental costs of SCR systems, as discussed below.

As described above for $SO_2$ controls, fuel switching to natural gas or an alternative coal source is not considered technically feasible.

***SNCR:*** Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SNCR is considered a technically feasible alternative is Nucla Unit 4.

***SCR:*** SCR systems are the most widely used post-combustion $NO_x$ control technology for PC-fired boilers. SCR control involves injecting ammonia into the flue gas stream in the presence of a catalyst, and requires a temperature range of 500°F – 800°F. SCR systems are not considered feasible for CFB boilers because the particles present in the boiler exhaust act as catalyst poisons. However, the recent BACT analyses for the Spiritwood and Bonanza Units have considered the application of SCR technology following the particulate control device on CFB boilers in order to achieve 90% $NO_x$ reduction. Since baghouse exhaust temperatures are too low to satisfy SCR requirements, reheating of the flue gas is required. $NO_x$ control efficiencies of 90% are expected. The Division considers SCR a technically feasible alternative for Nucla Unit 4. Please see the cost section for more details regarding SCR.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

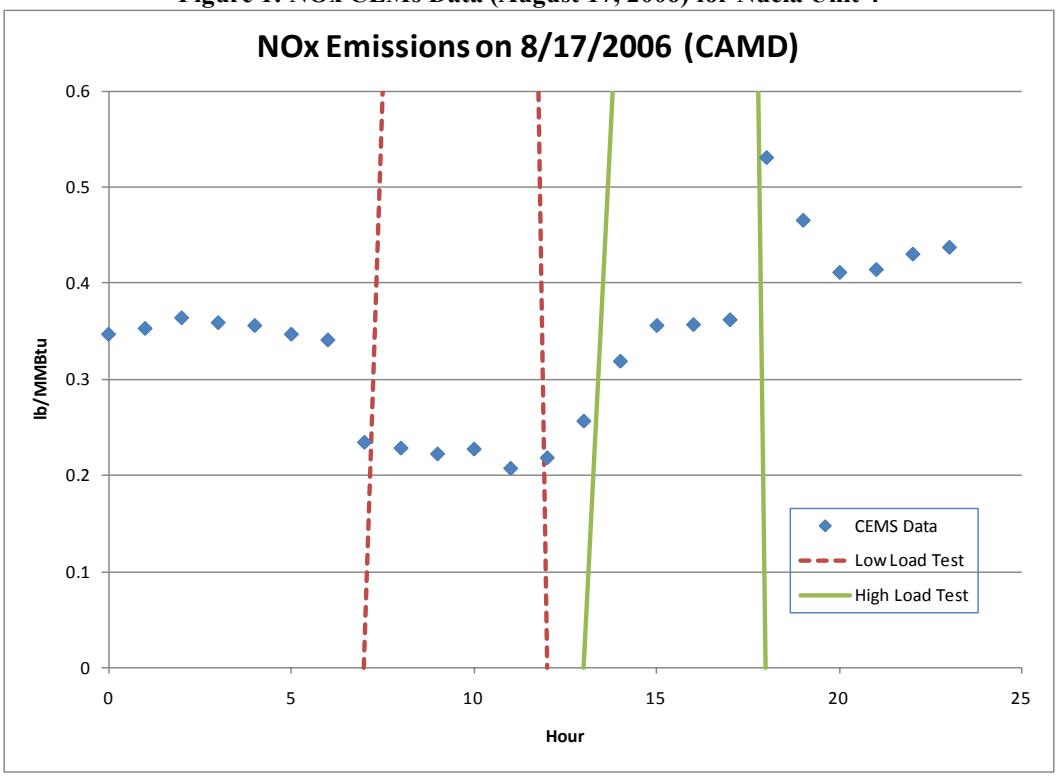
*SNCR:* The current SNCR system associated with Unit 4 is a small system using anhydrous ammonia injection for $NO_x$ trim during period when emissions approach 0.4 lb/MMBtu (the permit limit is 0.5 lb/MMBtu). $NO_x$ trim is required to ensure that the facility is able to meet the 1,987.9 ton per year permit limit on a rolling 12-month total. Tri-State notes that the unit is not in service the majority of the time. The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour, allowing only 8 days of continuous service. Tri-State also notes that there is such a wide variability in the effectiveness of SNCR for controlling $NO_x$ emissions that only 10% control should be assumed, but provided no data to support this value. Note that 10% control over a baseline of 0.39 lb/MMBtu is 0.35 lb/MMBtu.

On August 17, 2006, Tri-State performed a stack test in order to ensure that ammonia slip emissions resulting from the newly installed SNCR system would not result in a significant emission increase (for $PM_{10}$) and trigger PSD review for the project. The test was completed at maximum and minimum boiler loads, and maximum ammonia injection rate (15.4 – 15.5 gallons per hour)[25]. The test runs occurred during the following timeframes:

| Low Load (80.4 MW) | High Load (109.2 MW) |
|---|---|
| Run 1: 7:28 – 8:28 | Run 1: 13:51 – 14:51 |
| Run 2: 9:14 – 10:14 | Run 2: 15:25 – 16:25 |
| Run 3: 10:44 – 11:44 | Run 3: 16:52 – 17:52 |

The $NO_x$ CEMS data from CAMD for August 17, 2006 in Figure 1 shows an hourly $NO_x$ rate during the low load test of 0.22 lb/MMBtu (corresponding to 43.6% control over the baseline), and an hourly $NO_x$ rate during the high load test of 0.35 lb/MMBtu (corresponding to 10.3% control).

**Figure 1: NOx CEMs Data (August 17, 2006) for Nucla Unit 4**




The low load rate of control is more in line with estimates for the SNCR systems in the Spiritwood and Bonanza BACT analyses (58%[26] and 47%[27], respectively).

[25] Colorado Department of Public Health & Environment, November 2, 2006. "Stack Testing Report, Nucla Station"
[26] Barr, Appendix E, Page 56.
[27] EPA, Deseret Power Electric Cooperative…Page 49.

The Division conducted an analysis to determine the typical load for Nucla Unit 4 using baseline data (2006 – 2008). From 2006 – 2008, Nucla ran at 97.6% load. This high load data indicates that 10.3% control is more reasonable. However, the Division and Tri-State both note that the existing small scale SNCR system is not designed for full-scale operation and would last about 8 days in continuous service and has never operated for an extended period of time. Tri-State further notes that given the design purpose of the existing system for injection to trim emissions as needed, the system is not engineered to achieve a specific percent reduction. The Division concludes that there is a significant amount of uncertainty surrounding the application of SNCR on CFB boilers due to lack of information at this time.

Table 11 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 11: Nucla Unit 4 $NO_x$ Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Fuel switching – Natural gas or alternate coal source | Natural gas: 20 – 70% Alternate coal: minimal | Natural gas – N Alternate coal – Y – will not provide further NOx control |
| Low $NO_x$ Burners (LNB) | ~10% | N – CFB boiler |
| Overfire air (OFA) | 10 – 25% (alone) | N – CFB boiler |
| Selective non-catalytic reduction (SNCR) | 20 – 40% | Y – small scale system already installed |
| Selective catalytic reduction (SCR) | 70 – 90% | Y |

**Step 4: Evaluate Factors and Present Determination**

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[28] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nucla Unit 4 to determine control efficiencies and annual reductions.

[28] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

Factor 1: Cost of Compliance

*SCR:* Although SCR systems provide significantly higher levels of $NO_x$ removal over SNCR systems, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using SCR versus SNCR on a CFB Boiler is identified as $25,315/ton in the Spiritwood BACT analysis[29], and $40,297 per ton in the Bonanza BACT analysis[30]. A SCR system at the Nucla Station should be expected to have even higher costs than these examples due to a retrofit factor and small size. Therefore, the Division considers that costs for SCR will be excessive. Additionally, site-specific costs for SCR on Nucla are not available at this time.

*SNCR:* The cost associated with installation of an upgraded SNCR system is shown below. Costs are based on values submitted by Tri-State on May 14, 2010.[31] Refer to "Nucla APCD Cost Analysis" for more details. The Division used two discrete control efficiencies to demonstrate the significant uncertainty of the application of SNCR and the variation in resultant cost effectiveness.

Table 12 and Table 13 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 12: Nucla Unit 4 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,675 | 0.387 | |
| SNCR | 10.3 | 1,503 | 0.347 | 0.399 |
| SNCR | 43.6 | 945 | 0.218 | 0.251 |

**Table 13: Nucla Unit 4 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| SNCR | 173 | $2,238,592 | $12,974 | $12,974 |
| SNCR | 730 | $2,238,592 | $3,065 | --- |

[29] Barr, Appendix E, Page 57.
[30] EPA, Deseret Power Electric Cooperative…Page 51.
[31] Tri-State, Page 3.

Factor 2: Time Necessary for Compliance

Tri-State states that the SNCR project could be implemented in a two to three year time frame, but also notes that[32]:

> "Projects of this size entailing a significant outage lasting eight weeks or more must be integrated into the long term schedule in order to coordinate with the management of the grid and for power replacement commitments. The date on which EPA SIP approval occurs is necessarily the starting point for any schedule including significant investments for engineering and design, procurement of equipment and contract commitments. In addition, the schedule would have to be integrated into the electric supply planning process."

Tri-State has also described significant constructability challenges and balance-of-plant changes that will likely affect the timeframe for reconstruction of the SNCR project[33]. Nucla station is located approximately 70 miles from the nearest interstate highway. The facility does not have rail service and is located 40 miles from the nearest commercial air terminal. Below freezing temperatures are expected seven months of the year, which affects soil excavation, structure foundations and concrete placement.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. The cost associated with increased power needs was addressed in the cost effectiveness study provided by Tri-State and is reflected in the costs shown in the tables above.

Installing SNCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid.

[32] Ibid., Page 24.
[33] Ibid., Page 10.

With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; Tri-State has indicated that the larger quantity of on-site anhydrous ammonia storage required by the scale-up of the SNCR system will require the review and approval of new Risk Management Plans and Process Safety Management Plans. The larger tank may also trigger other state and local ordinances and requirements.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. Nucla has a limited, small-scale SNCR system for emissions trimming purposes already installed.

**Step 6: Select RP Determination**

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Nucla Unit 4 is the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

**Additional Analyses of SO2 and NOx Controls for Nucla**

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, and other relevant technologies such as lime spray dryers and flue gas desulfurization. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla.

Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

**Requirements for Nucla Station**

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual $NO_x$ limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options**
**For**
**Platte River Power Authority – Rawhide Energy Station**

I. Source Description

| | |
|---|---|
| Owner/Operator: | Platte River Power Authority |
| Source Type: | Electric Utility Steam Generating Unit |
| SCC (EGU): | 1010026 |
| Boiler Type: | Pulverized Coal Dry-Bottom Tangentially-Fired |

The Platte River Power Authority (PRPA) Rawhide Energy Station is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. The Rawhide Energy Station consists of one coal fired steam driven electric generating unit (Unit 101), with a rated electric generating capacity of 305 MW (gross), and was placed into service in 1984. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and a lime spray dry absorber controls sulfur dioxide ($SO_2$). The boiler is equipped with low nitrogen oxide ($NO_x$) concentric firing system (LNCFS) burners with separated overfire air (SOFA) configuration for minimization of $NO_x$ emissions, installed in 2005.

The Rawhide Station also has five natural-gas fired combustion turbines, designed to operate in a simple cycle mode, four rated at a heat input of 831.1 MMBtu/hour (approximately 82 MW) and one rated at a heat input of 1,400 MMBtu/hour (about 150 MW). Each turbine is equipped with integral dry low $NO_x$ combustion systems and inlet air fog cooling systems and startup and shutdown duration average $NO_x$ and CO emission limits determined to be Best Available Control Technology (BACT)[1] since each turbine is subject to Prevention of Significant Deterioration (PSD) provisions. These turbines were placed into service starting in May 2002, with the last turbine (150 MW) started up in June 2008. The primary use of these units is to meet Platte River's energy reliability and peak load requirements. The turbines operate on limited, intermittent, and unpredictable schedules as peak loading units. Additionally, the facility includes a number of fugitive dust sources. PRPA has prepared a Reasonable Progress (RP) analysis as well as supplemental information which can be found in "PRPA RP Submittals".

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Rawhide facility, and information about similar facilities to determine RP for $PM_{10}$ and $SO_2$ (available in the TSD). EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of $SO_2$, $NO_x$, or $PM_{10}$ equal

[1] Colorado Air Pollution Control Division, 2004. Colorado Operating Permit 03OPLR261: Rawhide Energy Station. Section II: Condition 1.7, pages 10 – 13.

to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for $SO_2$, $NO_x$ and $PM_{10}$ to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines "emissions unit" as "any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV (acid deposition control) of the federal act, or of the term "source" for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [2] ." These *de minimis* levels are as follows:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

Emissions Unit P301 serves as a detailed example of evaluating one "unit" in Table 1. As the PM10 emissions from emissions unit P301 are below the *de minimis* level of 15 tons per year, it is exempted from any further analysis under RP.

**Table 1: Unit Detail Example for *de minimis* Threshold**

| Unit P301 Breakdown | 2006 – 2008 Average $PM_{10}$ Emissions (Baseline Actual Emissions) |
|---|---|
| Solid Wastes Silo Rotary Unloader Discharge | 0.41 |
| Solid Wastes Hauling to Landfill | 1.64 |
| Solid Wastes Haul Truck Unloading | 0.02 |
| Active/Exposed Landfill Area | 0.21 |
| Waste Landfilling/Reclamation | 0.39 |
| Bottom Ash Excavation and Loading | 0.02 |
| Solid Wastes Silo Filling | 0.00 |
| Solids Vacuum Conveying System and Silo Filling | 0.17 |
| Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading | 0.02 |
| Unit P301 Baseline $PM_{10}$ Emissions | 3.01 << 15 (PSD threshold) |

Rawhide Unit 101 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. PRPA submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010. Table 2 depicts technical information for Rawhide Unit 101.

[2] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

**Table 2: Rawhide Unit 101 RP-eligible Emission Controls and Reduction (%)**

| | Rawhide Unit 101 |
|---|---|
| Placed in Service | 1984 |
| Boiler Rating, MMBtu/Hr for coal | 3,000 |
| Electrical Power Rating, Gross Megawatts | 305 |
| Description | Combustion Engineering tangentially fired, dry bottom steam generator/boiler firing pulverized coal. |
| Air Pollution Control Equipment | Fabric Filter (baghouse) for $PM/PM_{10}$ control<br>Spray Dryer Removal System for $SO_2$ control |
| Special Features | Low $NO_x$ Concentric Firing System (LNCFS) with separated overfire air (SOFA) installed in 2005 |
| Emissions Reduction (%)[1] | $NO_x$ – 49.6%<br>$SO_2$ – 83.1%<br>$PM/PM_{10}$ – 99.2/96.7% |

[1]Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for $PM/PM_{10}$. For $SO_2$ estimates, CAMD data (average of 2006 – 2008) was used to calculate reduction %. The $NO_x$ reduction is based on actual data from pre-2005 actual emissions. See "Rawhide APCD Technical Analysis" for further details. Not based on actual testing.

For the boiler, the Voluntary Emissions Reduction Agreement (VERA) permit limit for $NO_x$ is 0.180 lbs/MMBtu on an annual average effective July 15, 2006. The Acid Rain permit limit for $NO_x$ is currently 0.40 lbs/MMBtu on an annual average and the PSD/NSPS limit is 0.50 lbs/MMBtu on a 30-day rolling average.

In October of 2005, PRPA installed a low $NO_x$ Concentric Firing System (LNCFS) with separated overfire air (SOFA) on Unit 101 that resulted in an approximate 50% reduction of $NO_x$ emissions (from pre-2005 actual emissions) in accordance with the Voluntary Emissions Reduction Agreement entered into with the State of Colorado in 2002[3].

Rawhide Unit 101 was initially installed in 1984 with a baghouse for particulate emission ($PM/PM_{10}$) control, with control efficiency exceeding 99.9%. This system was BACT at the time of initial startup and is still considered BACT currently.

The "Spray Dryer Removal System" for Unit 101 was considered a new control technology at the time of installation in 1984 and started up at the same time as Rawhide Unit 101. This system originally reduced $SO_2$ emissions by approximately 80% and 0.13 lbs/MMBtu (30-day rolling average) (from AP-42 emission calculations) according to Federal PSD emission standards at that time (0.2 lbs/MMBtu annually). In 2003, PRPA entered into a Voluntary Emissions Reduction Agreement with the State of Colorado to reduce $SO_2$ emissions to 0.09 lbs/MMBtu (annual

[3] Colorado Air Pollution Control Division, 1992. Exhibit A: Division Evaluation of Nitrogen Oxides Emission Limitation and Regulatory Assurance Periods.

average) by upgrading the lime spray dryer system[4]. This upgraded system resulted in an approximate 30% emission rate reduction of $SO_2$ emissions from pre-VERA emission rates.

## II. Source Emissions

Table 3 summarizes the $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 4 summarizes each unit at the facility and applicable $NO_x$, $SO_2$, and $PM_{10}$ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

**Table 3. Summary of 2006 - 2008 Averaged Emissions - PRPA Rawhide Facility**

| $NO_x$ (tons/year) | $SO_2$ (tons/year) | $PM_{10}$ (tons/year) |
|---|---|---|
| 1,885 | 914 | 125 |

**Table 4. Summary of 2006 - 2008 Averaged Emissions by Unit - PRPA Rawhide Facility**

| Unit | Pollutant | 2006 | 2007 | 2008 | 2006 - 2008 average* |
|---|---|---|---|---|---|
| Unit 101 Boiler | $SO_2$ (tons) | 943 | 928 | 869 | 913 |
| | $SO_2$ (lb/ MMBtu) | 0.078 | 0.081 | 0.078 | 0.081 |
| | $NO_x$ (tons) | 1,990 | 1,863 | 1,745 | 1,866 |
| | $NO_x$ (lb/ MMBtu) | 0.163 | 0.162 | 0.173 | 0.166 |
| | $PM_{10}$ (tons) | 109 | 113 | 101 | 108 |
| | $PM_{10}$ (lb/ MMBtu) | 0.018 | 0.017 | 0.018 | 0.018 |
| *Turbine Unit A (82 MW)* | *$SO_2$ (tons)* | *0.10* | *0.12* | *0.12* | *0.11* |
| | *$NO_x$ (tons)* | *1.17* | *5.45* | *0.75* | *2.46* |
| | *$PM_{10}$ (tons)* | *0.20* | *1.12* | *0.13* | *0.48* |
| *Turbine Unit B (82 MW)* | *$SO_2$ (tons)* | *0.09* | *0.06* | *0.11* | *0.09* |
| | *$NO_x$ (tons)* | *3.87* | *3.17* | *5.07* | *4.04* |
| | *$PM_{10}$ (tons)* | *0.77* | *0.58* | *0.99* | *0.78* |
| *Turbine Unit C (82 MW)* | *$SO_2$ (tons)* | *0.04* | *0.09* | *0.03* | *0.05* |
| | *$NO_x$ (tons)* | *2.03* | *4.45* | *1.65* | *2.71* |
| | *$PM_{10}$ (tons)* | *0.33* | *0.80* | *0.30* | *0.48* |
| *Turbine Unit D (82 MW)* | *$SO_2$ (tons)* | *0.05* | *0.10* | *0.03* | *0.06* |
| | *$NO_x$ (tons)* | *2.53* | *4.95* | *1.50* | *2.99* |
| | *$PM_{10}$ (tons)* | *0.45* | *0.85* | *0.26* | *0.52* |
| *Turbine Unit F (150 MW)*** | *$SO_2$ (tons)* | | | *0.38* | *0.38* |
| | *$NO_x$ (tons)* | | | *20.45* | *20.45* |
| | *$PM_{10}$ (tons)* | | | *3.75* | *3.75* |
| *P201 Train Unloading Facility* | *$PM_{10}$ (tons)* | *0.60* | *0.01* | *0.01* | *0.20* |
| *P201 Active Coal Pile Reclaim* | *$PM_{10}$ (tons)* | *0.03* | *0.02* | *0.00* | *0.02* |
| *P201 Coal Silo Filling and Conveyor Belt Transfer* | *$PM_{10}$ (tons)* | *0.30* | *0.00* | *0.00* | *0.10* |
| *P201 Coal Silo Discharge to Conveyor Belt* | *$PM_{10}$ (tons)* | *0.28* | *0.00* | *0.00* | *0.10* |
| *P201 Coal Crushing and* | *$PM_{10}$ (tons)* | *0.33* | *0.02* | *0.02* | *0.12* |

[4] Colorado Air Pollution Control Division, 1992. Exhibit B: Division Evaluation of Sulfur Dioxides Emission Limitation and Regulatory Assurance Periods.

| *Conveying* | | | | | |
|---|---|---|---|---|---|
| *P201 Coal Conveyor Belt Transfer* | *$PM_{10}$ (tons)* | *0.30* | *0.00* | *0.00* | *0.10* |
| *P201 In-Plant Silo Filling Conveyor Belt Transfer* | *$PM_{10}$ (tons)* | *0.30* | *0.00* | *0.00* | *0.10* |
| *P201 Coal Pile Stockout* | *$PM_{10}$ (tons)* | *1.18* | *0.01* | *0.02* | *0.40* |
| *P201 Active Coal Storage Area* | *$PM_{10}$ (tons)* | *0.93* | *1.91* | *1.96* | *1.60* |
| *P201 Active Coal Pile Storage Area* | *$PM_{10}$ (tons)* | *0.95* | *2.56* | *2.56* | *2.02* |
| *P201 Coal Crusher Stockout* | *$PM_{10}$ (tons)* | *0* | *0* | *0* | *0.00* |
| *P201 Coal Conveying* | *$PM_{10}$ (tons)* | *1.81* | *1.23* | *1.09* | *1.38* |
| *P301 Solid Wastes Silo Rotary Unloader Discharge* | *$PM_{10}$ (tons)* | *0.70* | *0.28* | *0.25* | *0.41* |
| *P301 Solid Wastes Hauling to Landfill* | *$PM_{10}$ (tons)* | *1.82* | *1.67* | *1.44* | *1.64* |
| *P301 Solid Wastes Haul Truck Unloading* | *$PM_{10}$ (tons)* | *0.04* | *0.02* | *0.01* | *0.02* |
| *P301 Active/Exposed Landfill Area* | *$PM_{10}$ (tons)* | *0.19* | *0.24* | *0.19* | *0.21* |
| *P301 Waste Landfilling/Reclamation* | *$PM_{10}$ (tons)* | *0.13* | *0.57* | *0.46* | *0.39* |
| *P301 Bottom Ash Excavation and Loading* | *$PM_{10}$ (tons)* | *0.03* | *0.02* | *0.02* | *0.02* |
| *P301 Solid Wastes Silo Filling* | *$PM_{10}$ (tons)* | *0.02* | *0.20* | *0.17* | *0.13* |
| *P301 Solids Vacuum Conveying System and Silo Filling* | *$PM_{10}$ (tons)* | *0.17* | *0.18* | *0.16* | *0.17* |
| *P301 Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading* | *$PM_{10}$ (tons)* | *0.02* | *0.02* | *0.01* | *0.02* |
| *P401 Scrubber Lime Storage Silo Filling* | *$PM_{10}$ (tons)* | *0* | *0.01* | *0.01* | *0.00* |
| *P401 Recycle Ash Storage Silo Filling* | *$PM_{10}$ (tons)* | *0.11* | *0.89* | *0.81* | *0.60* |
| *P501 Unpaved Site Roadways and Parking Lots* | *$PM_{10}$ (tons)* | *3.14* | *3.92* | *4.23* | *3.76* |
| *P501 PRS Soda Ash Storage Silo Filling* | *$PM_{10}$ (tons)* | *0* | *0* | *0* | *0.00* |

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages for the Unit 101 Boiler are estimated to be 5-15% higher than the annual average emission rate (i.e. the maximum 30-day $NO_x$ rolling average is likely about 0.190 lbs/MMBtu).
**Note that Unit F did not start up until June of 2008; therefore it was not operated in 2006 or 2007 and for only half of 2008.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Each of the five turbines at Rawhide Station was installed with an advanced dry low-$NO_x$ combustion system that controls $NO_x$ emissions to less than 9 ppm @ 15% $O_2$ as well as a gas turbine inlet air fog cooling system designed for optimal power augmentation during hot weather operations. . Each turbine is subject to BACT under the PSD provisions. The turbines are also

required to use pipeline quality natural gas as defined by the Acid Rain Provisions 40 CFR Part 72. The Title V permit enforces a compliance $SO_2$ emission factor of 0.0006 lb/MMBtu for each turbine. These combustion turbines are further evaluated within the source category "Combustion Turbines" in Section 8.2.3 of the Regional Haze SIP.

## III. Units Evaluated for Control

As documented by PRPA, Rawhide Unit 101 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

**Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)**

| | Specifications | | |
|---|---|---|---|
| Emission Unit | Fuel Heating Value (Btu/lb) | Sulfur (% by weight) | Ash (% by weight) |
| Rawhide Unit 101 | 8,853 | 0.24 | 5.42 |

Table 4 lists the units at Rawhide that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

**Table 6: Uncontrolled emission factors for Rawhide Unit 101**

| Emission Unit | Pollutant | Fuel |
|---|---|---|
| | | Coal (sub-bituminous) (lb/ton) |
| Rawhide Unit 101[5] | $NO_x$ | 7.2 |
| | $SO_2$ | 35 x %S = 8.5* |
| | $PM/PM_{10}$ | PM – 54.2**<br>$PM_{10}$ – 12.5 |

*%S = % of sulfur present in coal supply. For example, 35 x 0.24 = 8.5
**%A = % of ash present in coal supply. For example, 10 x 5.42 = 54.2

## IV. Reasonable Progress Evaluation of Unit 101

### *a. Sulfur Dioxide*

**Step 1: Identify All Available Technologies**

PRPA identified one $SO_2$ control option:

***Fuel Switching – Natural Gas or Colorado Coal***

The Division requested that PRPA evaluate the option below, and received relevant information for this request on May 5, 2010:

***Dry FGD upgrades***

As discussed in EPA's BART Guidelines[6], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls.

[5] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[6] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system

**Step 2: Eliminate Technically Infeasible Options**

***Fuel Switching – Natural Gas or Colorado Coal:*** The Division and PRPA both assert that the Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications and natural gas pipeline construction. Conversion from coal to natural gas would reduce $SO_2$ emissions by about 906 tons per year, or approximately 99% (using 2006 - 2008 CAMD data average)[7]. $SO_2$ emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the dry FGD – lime spray dryer system in place, Unit 101 currently achieves an emission rate of 0.07 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible as well as economically impractical to change coal supplies. The sulfur content of the Rawhide Unit 101 PRB coal supply is between 0.8 – 1.4 lb/MMBtu with most of the supply containing less than 1.2 lbs/MMBtu (based on northern Wyoming PRB coal mine reports). The average sulfur content in the coal is 0.29%. PRPA obtains coal for Rawhide Unit 101 from the Antelope Mine in Converse County, Wyoming, which has one of the lowest sulfur content of any mine in the county. PRPA additionally pays a premium to ensure higher Btu/lower sulfur coal. A review by the Colorado Geological Survey found that on average, Wyoming coal had similar sulfur content to Colorado coal[8]. Virtually all Colorado coal contains less than 1 percent sulfur and most of it contains less than half of that amount (0.5% or less)[9]. Therefore, the sulfur content of the Antelope Mine coal is similar, if not lower, than Colorado coal.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101. However, fuel switching to Colorado coal will not further reduce $SO_2$ emissions from Unit 101 and will not be considered further in this analysis.

***Dry Flue Gas Desulfurization (FGD) Upgrades:*** Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power

[7] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D of the SIP for detailed calculations.
[8] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf
[9] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf

plants[10]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures $SO_2$ by using a slaked lime containing slurry that is sprayed into the flue gas and reacts with the $SO_2$ to form calcium sulfate, and then is subsequently dried by the heat of the flue gas, and collected in a particulate control device.

Rawhide Unit 101 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for $SO_2$ removal from the gaseous emission stream of a utility boiler. PRPA has since upgraded this system (in 2002) and currently achieves greater than 80% $SO_2$ removal, with an actual annual average of 0.07 lb/MMBtu and a permit limit of 0.09 lb/MMBtu on an annual average basis, 0.13 lb/MMBtu on a 30-day average, and 0.19 lbs/MMBtu on a 3-hour rolling average. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[11]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to Appendix D for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of $SO_2$ emissions found that lime spray drying processes have a range of design efficiencies from 70 – 96% and a median design efficiency of 90%; however, application conditions may differ (e.g. coal sulfur percent)[12] .

PRPA submitted a $SO_2$ upgrade analysis to the Division on May 6, 2010 upon request regarding potential upgrades for the dry FGD scrubber system. PRPA asserts that operating the SO2 scrubber at the 0.09 lbs/MMBtu VERA limit pushes many of the scrubber's material handling and slurry preparation sub-systems to the limits of their design capacity. As part of the VERA scrubber improvements, the recycle ash pressure feeders were upgraded and the recycle ash conveying line was replaced with larger diameter piping to increase the recycle ash conveying capacity between the solids waste silo and recycle ash storage bin/silo. Moving beyond current levels of scrubber operation would require additional equipment upgrades and would reduce the existing redundancy in some critical scrubber sub-systems. Specifically, the recycle ash blowers, bin vent filter on recycle ash silo, feed slurry preparation pumps, and feed slurry tanks are all operating at maximum throughput levels or at the margin and would need to be replaced with larger capacity equipment. While there is usually available redundancy within the lime slaking sub-system, a lower $SO_2$ limit would diminish this available capacity and likely also require an upgrade to ensure adequate margin.

PRPA notes that the $SO_2$ scrubber has three atomizer reaction compartments that provide critical operating flexibility. The scrubber generally operates with all three compartments in-service,

[10] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[11] Colorado Operating Permit 96OPLR142 pg. 5 – $SO_2$ 30-day rolling average limit is 0.13 lb/MMBtu.
[12] EPA, 2000. "Controlling $SO_2$ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.

which provides maximum reaction/residence time, eases $SO_2$ removal equipment demands, and minimize pressure drop. Though not a desirable operating mode, the scrubber is currently capable of operating at full load with only two atomizer compartments in-service. In addition to the improved scrubber performance, the current atomizer compartment redundancy provides critical atomizer operational and maintenance flexibility, ensuring environmental compliance, and providing for high $SO_2$ scrubber and unit availability. Achieving a lower $SO_2$ limit may compromise atomizer compartment redundancy, which will significantly diminish scrubber operational and maintenance flexibility. This loss of redundancy and flexibility will likely result in increase malfunctions and could also affect unit availability if load reduction is triggered.

Even with the potential scrubber equipment upgrades, additional $SO_2$ reductions will still present unacceptable operational challenges. $SO_2$ scrubbing is limited by scrubber outlet temperatures which must remain above the fluegas dew point with an adequate margin to prevent condensation and catastrophic damage to the baghouse. Over-spraying below minimum SDA outlet temperatures also results in higher moisture ash in the baghouse that is difficult to convey from the collection hoppers.

Given existing spray-down temperature constraints, reducing $SO_2$ emissions below 0.09 lbs/MMBtu requires additional lime to increase feed slurry reactivity. At higher $SO_2$ removal rates, the lime/$SO_2$ stoichiometry increases and more unreacted lime is carried-over with the flyash and scrubber waste to the baghouse. The higher lime content in the flyash and scrubber waste affects the fluidity of the material making it harder to pneumatically convey out of and between the baghouse hoppers, solid waste silo, and recycle ash storage bin/silo. Hopper bridging and conveying piping pluggage are significant operational and maintenance issues impacting $SO_2$ scrubber reliability. Lowering the $SO_2$ emissions below the VERA limit will increase the potential for scrubber and baghouse malfunctions.

PRPA examined BART-guideline dry scrubbing potential upgrades, with the following results:

-*Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of $SO_2$ scrubber performance additives applicable to the Unit 101 SDA system. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Use of more reactive sorbent*: Lime quality is critical to achieving the VERA emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with the VERA limit. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 $SO_2$ scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements are designed to improve the reactivity of the slaked lime-milk slurry. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-nozzle design. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

The Division concludes that upgrades are not technically feasible for the Unit 101 Boiler.

Fuel switching to Colorado coal will not provide further $SO_2$ emission reductions. Rawhide Unit 101 has a SDA system for which the State has determined that no upgrades are feasible. Therefore, the Division has conducted a four-factor analysis for reasonable progress for fuel switching to natural gas regarding $SO_2$ reductions.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

*Fuel Switching – Natural Gas:* Conversion from coal to natural gas would reduce $SO_2$ emissions by almost 100% from the boiler using EPA's AP-42 emission factors[13] and concurs with PRPA's submittal.

Table 7 summarizes each available technology options and technical feasibility for $SO_2$ control on Rawhide Unit 101.

**Table 7: Rawhide Unit 101 SO2 Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Wet FGD | 52-98%, median 90%[14] | Y – not evaluated |
| Dry FGD | 70 – 90% | Y - installed |
| DSI (Trona) | 60-65% | Y – not evaluated, will not provide further SO2 control |
| Fuel switching – different coal type | None | Y – will not provide further SO2 control |
| Use of performance additives | None | N |
| Use of more reactive sorbent | None | N |
| Increase the pulverization level of sorbent | None | N |
| Engineering redesign of atomizer or slurry injection system | None | N |
| Fuel switching – natural gas | 99% (EPA AP-42) | Y |

**Step 4: Evaluate Factors and Present Determination**

[13] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[14] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Factor 1: Cost of Compliance

In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million by PRPA[15]. This results in an initial control cost, using EPA's Cost Control Manual[16] to estimate annual operating costs, of about $262,000 per ton of $SO_2$ removed annually[17]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability, which was not taken into account in the 2008 study[18].

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[19]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

Table 8 and Table 9 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors.[20]

**Table 8: Unit 101 Control Resultant $SO_2$ Emissions**

| Alternative | Control Efficiency (%)* | Resultant Emissions** | |
|---|---|---|---|
| | | (tons/year) | (lb/MMBtu) |
| Baseline | --- | 913 | 0.08 |
| Fuel Switching - NG | 99% | 7.7 | 0.0006 |

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas $NO_x$ lb/MMBtu estimate.

** Division calculated from average baseline years (2006 – 2008). This is an **annual** average.

**Table 9: Unit 101 $SO_2$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($)* | Cost Effectiveness ($/ton)* | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | n/a |

[15] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[16] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.
[17] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.
[18] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[19] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm
[20] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

| | | | | |
|---|---|---|---|---|
| Fuel Switching - NG | 906 | $237,424,331 | $262,169 | $262,169 |

* Division estimate based on PRPA submittal estimating direct capital cost at $50,000,000, current delivered coal costs at ~$20/ton, EPA Cost Control Manual, and EPA AP-42 emission factors for natural gas.

Platte River noted that the Division natural gas cost analysis does not account for replacement power for the lost generation. The Rawhide Natural Gas Conversion Study performed by B&V estimated that a 100% fuel switch would result in a loss of approximately 30 MW, in addition to the increased heat rate which was considered.

Platte River asserts that replacement power cost and associated emissions would depend on the specific source. Replacement with coal-fired sources would run in the $20 - $25/MWh range ($5.3 - $6.6 million/year), while natural gas-fired sources would run in the $60 - $125/MWh range ($15.8 – 32.8 million/year). Unaccounted $NO_x$ emissions from the replacement power sources would likely be around 1.5 lbs/MWh (197 tons/year) for well combustion controlled coal-fired sources, and 0.36 lbs/MWh (47 tons/year) for natural gas-fired sources. The replacement power prices reflect current conditions and will need to be escalated over the 20-year 4-factor evaluation period. $SO_2$ emissions would likely be in the 0.7 lbs/MWh (92 tons/year) for well controlled coal-fired sources and 0.007 lbs/MWH (1 ton/year) for natural gas-fired sources. Table 7 below summarizes these costs and emissions.

**Table 10: Unaccounted for Replacement Power Cost & Emissions Estimates (30 MW)**

| Power Source | Lower Cost ($/MWh) | Lower Cost ($ million/year) | Higher Cost ($/MWh) | Higher Cost ($ million/year) |
|---|---|---|---|---|
| Coal | $20 | $5.26 | $25 | $6.57 |
| Natural Gas | $60 | $15.77 | $125 | $32.85 |
| Power Source | $NO_x$ (lbs/MWh) | $NO_x$ (ton/year) | $SO_2$ (lb/MWh) | $SO_2$ (ton/year) |
| Coal | 1.5 | 197 | 0.7 | 92 |
| Natural Gas | 0.36 | 47 | 0.007 | 1 |

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[21], the Division anticipates that, taking into account the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

[21]Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

Factor 3: Energy and Non-Air Quality Impacts

The Division has determined that there are not any negative energy or non-air quality related impacts related to fuel switching to natural gas for the Unit 101 boiler. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. **Error! Reference source not found.** depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

**Table 11: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| $SO_2$ Control Scenario | Unit(s) | SO2 Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr $SO_2$ rates | 101 | 0.11 | RMNP | 20 | --- | --- | 6 | --- | --- |
| dry FGD | 101 | 0.09 | | n/a | | | | | |
| dry FGD | 101 | 0.07 | | 20 | 19 | 1 | 6 | 4 | 2 |
| Fuel Switching - NG | 101 | 0.001 | | n/a | | | | | |

**Table 12: Visibility Results - SO2 Control Scenarios**

| SO2 Control Scenario | Unit(s) | SO2 Emission Rate | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | (lb/MMBtu) | (deciviews) | (deciviews) | (%) |
| Max 24-hr $SO_2$ rates | 101 | 0.11 | 0.871 | | |
| dry FGD | 101 | 0.09* | 0.87 | 0.01 | 1% |
| dry FGD | 101 | 0.07 | 0.84 | 0.03 | 3% |
| Fuel Switching - NG | 101 | 0.001 | 0.00 | 0.87 | 100% |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "PRPA Modeling Summary" for more details.

Determination

The Division evaluated emission limit tightening based on current operations through the four-factor analysis. PRPA's average 30-day rolling emission rate during the baseline period (2006 – 2008) was 0.09 lb/MMBtu. The maximum 30-day rolling emission rate during this period was 0.13 lb/MMBtu. Please refer to "Rawhide Cost Analysis" for more detail. The Division and PRPA agree that Rawhide can meet an emission limit of 0.11 lb/MMBtu (30-day rolling average).

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is the following SO2 emission rate:
Rawhide Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state has determined that these emissions rates are achievable without additional capital investment. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

### *b. Filterable Particulate Matter ($PM_{10}$)*

PRPA Unit 101 is currently equipped with two twelve-compartment fabric filter baghouses to control PM/$PM_{10}$ emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

PRPA states that the baghouses are able to control PM/$PM_{10}$ emissions to 0.03 lb/MMBtu and further notes that that the baghouses meet a 99.9+% control efficiency. The source was tested on November 18, 2009 and ran at 0.0023 lb/MMBtu, 92% lower than the permit limit (Method 5 – filterable portion). This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel. A Division review of the PM/$PM_{10}$ emission limits in the current Title V permit revealed that these limits are for filterable PM/$PM_{10}$ emissions only.

A Division review of EPA's RBLC revealed recent BACT PM/$PM_{10}$ determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is well within the range of recent BACT determinations.

The State has determined that the existing Unit 101 regulatory emissions limits of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/$PM_{10}$. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/$PM_{10}$ is not needed for Rawhide Unit 101.

### *c. Nitrogen Oxides ($NO_x$)*

**Step 1: Identify All Available Technologies**
PRPA identified eight $NO_x$ control options:
Fuel Switching – Natural Gas
Selective non-catalytic reduction (SCNR)
Selective catalytic reduction (SCR)
Separated overfire Air (SOFA)
Low $NO_x$ Burners (LNB)
LNB + SOFA
ECC – Enhanced Combustion Control

The Division also identified and examined the following additional control options:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[22]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the greater than 70% $NO_x$ reduction already being achieved at Unit 101. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

**Step 2: Eliminate Technically Infeasible Options**

***Fuel Switching – Natural Gas:*** The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. $NO_x$ emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the LNB+SOFA system in place, Unit 101 currently achieves an emission rate of 0.17 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible and economically impractical to change coal supplies. With fuel switching to natural gas, $NO_x$ emissions were projected to drop from the current 0.17

[22] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

lbs/MMBtu to a rate of 0.1 lbs/MMBtu[23]. However, this reduction would be diminished by the accompanying loss in boiler efficiency, increased boiler heat input requirement, and significant loss of generation resulting from natural gas firing.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101.

***LNB/ROFA®/SOFA/LNB+SOFA:*** The boiler is already equipped with a tangentially-fired LNB+SOFA system that was installed in 2005. This system achieves an approximate 50% $NO_x$ reduction (based on actual emissions).

***SNCR:*** Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. The optimum temperature window for Rawhide Unit 101 will most likely occur somewhere at the top of the furnace and in the backpass of the boiler if SNCR is applied. SCNR is considered a technically feasible alternative for Unit 101.

***SCR:*** SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 101 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Rawhide Station. Therefore, high-dust SCR is a technically feasible alternative for Rawhide Unit 101.

[23] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

***ECC:*** The enhanced combustion control system option for Rawhide Unit 101, submitted by PRPA, consists of a neural-net based combustion optimization subsystem (software and hardware) and companion real-time boiler combustion constituents and temperature measurement system. These system components are interfaced with the boiler's standard coordinated combustion control system (CCS). The ECC system continuously measures and monitors the dynamic boiler combustion constituents, temperatures and other process parameters. The ECC system then commands the CCS to manipulate variables such as combustion air damper positions, burner tilts, coal feeder speeds, and other process parameters to optimize fuel combustion and boiler efficiency, while controlling $NO_x$ and CO emissions within targeted ranges. Optimizing the ECC requires periodic combustion testing and CCS tuning. ECC is a technically feasible option for Rawhide Unit 101.

***ECO®:*** The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[24] and thus, is considered technically infeasible.

***RRI:*** Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[25] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 101.

***Coal Reburn + SNCR:*** Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[26]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

**Step 3: Evaluate Control Effectiveness of Each Remaining Technology**

***Fuel Switching – Natural Gas:*** The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. Conversion from coal to natural gas would reduce $NO_x$ emissions by about 545 tons per year, or approximately 29% (using 2006 - 2008 CAMD data average)[27].

[24] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[25] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[26] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[27] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.

*SNCR:* Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[28] to conservatively approximate that Rawhide Unit 101 can achieve up to 30% control when SNCR is applied. PRPA asserts that $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. However, if ammonia slip is controlled closer to 2 ppm then achievable $NO_x$ reduction efficiencies will be closer to 20 percent.

*SCR:*PRPA approximates that SCR can achieve an approximate 64% $NO_x$ reduction from the current low 0.17 lb/MMBtu baseline emission rate. PRPA asserts that while a lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for PRPA, a retrofit SCR, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% $NO_x$ emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction from an assumed baseline emission rate of 0.5 lb/MMBtu.[29,30] However, in the Division's experience and national CAMD emissions data (2009) reflect that an emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

Table 13 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 13: Rawhide Unit 101 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners (LNB) | 10-30% | Y – installed |
| LNB + OFA | 25-45% | Y – installed |
| Air Staging – overfire air (OFA) | 5-40% | Y – installed |
| Rotating overfire air (ROFA) | 45-65% | Y – will not increase current $NO_x$ reductions |
| SCNR | 20 – 40% | Y |
| SCR – HTSCR | Up to 90% | Y-high-dust arrangement |
| SCR – LTSCR | | |
| SCR – RSCR | | |
| Fuel switching – Natural gas | 20-70% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Coal reburn+SNCR | n/a | N |
| ECC | 15-25% | Y |

[28] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[29] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[30] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

**Step 4: Evaluate Factors and Present Determination**

Factor 1: Cost of Compliance

*SNCR:* A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[31] The PRPA-estimated SNCR costs for operating expenses is 44% for Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. The cost effectiveness for SNCR on Unit 1 is $3,168 per ton $NO_x$ reduced. Recent NESCAUM studies estimate SNCR retrofits achieving $NO_x$ emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[32,33] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced. [34]

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SNCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SNCR project cost considerations were:

- 
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101
- Three levels of automatic injection lances with retract system to accommodate SNCR reaction temperature and boiler turndown requirements.
- Computer flow/temperature modeling to establish optimum ammonia injection locations and flow patterns,
- Boiler waterwall modifications for injector lances and steam piping modifications for performance optimization,
- Electrical Motor Control Center switch gear upgrades and modifications to support urea system and ammonia delivery system,
- Reagent storage tank,
- Digital Control System (DCS) computer system hardware and control logic upgrades,
- Fluegas temperature and NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Interest costs during construction, and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns.

[31] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[32] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[33] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Platte River notes that the SNCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline $NO_x$ emission rates for the above reasons.

There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[35] Although PRPA's estimates are greater than these ranges, the reasons above lead the Division to the conclusion that PRPA's cost estimates for SNCR are reasonable.

*SCR:* SCR reagent materials, such as urea and/or ammonia, primarily use a limited resource, natural gas. Therefore, future costs for these materials may fluctuate widely. These costs are not included in the overall $/ton projections.

EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing PRPA's estimate, the Division found that the ratio of annual costs to the total capital costs for all control technologies projected by PRPA to be slightly lower than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for SCR for Unit 101 are 10.5% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[36]. Therefore, the Division concurs that PRPA's estimate is consistent with annual costs estimated by other facilities.

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SCR project cost considerations were:

- Vertical oriented high-dust SCR reactor configuration,
- Construction crane access constraints due to north-side coal conveyor and ACI silo, and south-side underground 84 inch circulating water line,
- Preliminary design and layout analyses including foundations, structural columns, cantilevered support steel, and main trusses support structures,
- Modification to existing structures including demolition of ductwork between the economizer and the air heater inlet,
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101,

[35] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[36] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

- Induced draft (ID) fan higher hp motor replacement and retrofit issues,
- Auxiliary power and switch gear upgrades and modifications to support two new ID fan motors,
- Digital Control System (DCS) computer system hardware and control logic upgrades including new electrical and controls building located adjacent to SCR,
- NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Three layer (two catalyst and one initial spare) reactor sizing for maximizing catalyst utilization,
- Reactor design to accommodate both ceramic honeycomb and plate type catalyst products to insure future procurement flexibility,
- Rerouted underground utilities (bottom-ash sluice trench and drain piping) due to SCR foundation requirements,
- Added superstructure costs due to fully enclosed plant, including boiler and air heater areas for cold-weather concerns requiring roof and wall penetrations and modifications,
- Higher structural costs due to high wind loading ,
- High gas temperature design issues (>800°F economizer gas temperature results in higher grade catalyst and steel issues), and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns,
- Interest costs during construction, and
- Lost generation revenue costs during outage.

Platte River notes that the SCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline $NO_x$ emission rates for the above reasons. The Division asserts that $/KW is not an appropriate metric when a detailed cost estimate has be developed. $/KW is rough estimate of controls for back of the envelope discussions and should not serve as cost estimate in light of more refined estimates. Therefore, the Division did not adjust PRPA's estimates for capital costs.

*Fuel Switching – Natural Gas*: In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million. Conversion from coal to natural gas would reduce $NO_x$ emissions by about 545 tons per year (using 2006 - 2008 CAMD data average). This results in an initial control cost, using EPA's Cost Control Manual to estimate annual operating costs, of about $436,000 per ton of $NO_x$ removed annually[37]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability. Tables 9 and 10 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors. The annual cost to control was determined using a capital

[37] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D SIP for detailed calculations.

recovery factor based on an approximate 8% interest rate. Refer to "Rawhide Cost Analysis" for more details.

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[38]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

*ECC*: PRPA worked with three different vendors on an enhanced combustion control pilot system. The cost estimates provided are from this pilot project. The annualized cost of approximately $288,500 is much lower than SNCR, which achieves about the same amount of control. This is little available cost information regarding this type of boiler modification. Since the costs are comparable or lower than other pre-combustion technologies, the Division concurs that PRPA's cost estimate is reasonable.

Table 14 and Table 15 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 14: Unit 101 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 1,866 | 0.166 | |
| ECC | 24.0 | 1,418 | 0.126 | 0.145 |
| SNCR | 27 | 1,362 | 0.121 | 0.140 |
| Fuel Switching - NG | 29.2** | 1,321 | 0.118 | 0.135 |
| SCR | 63.5 | 681 | 0.061 | 0.070 |

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas $NO_x$ lb/MMBtu estimate.

** Control efficiency provided in PRPA's analysis based on 0.17 lb/MMBtu $NO_x$ input, equivalent to 2006 – 2008 baseline conditions. Refer to "Rawhide Cost Analysis" for more information.

**Table 15: Unit 101 $NO_x$ Cost Comparison**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |

[38] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

| | | | | |
|---|---|---|---|---|
| ECC | 448 | $ 288,450 | $644 | $644 |
| SNCR | 504 | $1,596,000 | $3,168 | $23,357 |
| Fuel Switching - NG | 545 | $237,424,331 | $435,681 | $5,735,260 |
| SCR | 1,185 | $12,103,000 | $10,214 | ($352,073) |

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[39], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

PRPA anticipates that the time necessary for completing design, permitting, procurement, control equipment installation, and system startup and shakedown, after SIP approval, would be approximately 2-3 years for SNCR and 3-4 years for SCR. These timeframes may also vary somewhat to schedule the necessary major maintenance outage with other regionally affected utilities. The ECC option timeframe is much shorter due to the fact that PRPA has already been working with independent vendors on this system. Therefore, this system could be functional within 6 months of SIP approval.

Factor 3: Energy and Non-Air Quality Impacts

SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR and SNCR reagent injection system have minimal power requirements.

Post-combustion add-on control technologies like SCR and SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. 100 – 300 kW is less than 0.5% of the power generated by the Unit 101 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in

[39] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. PRPA has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to Appendix D for more information.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor doesn't influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

**Table 16: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler | NOx Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hr NOx rate | 101 | 0.302 | Rocky Mountain National Park | 20 | --- | --- | 6 | --- | --- |
| ECC | 101 | 0.126 | | 20 | 6 | 14 | 6 | 1 | 5 |
| SNCR | 101 | 0.121* | | n/a | | | | | |
| Fuel Switching - NG | 101 | 0.118* | | n/a | | | | | |
| SCR | 101 | 0.061 | | 20 | 1 | 19 | 6 | 0 | 6 |

**Table 17: Visibility Results - NOx Control Scenarios**

| NOx Control Scenario | Boiler | NOx Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hr NOx rate | 101 | 0.302 | 0.87 | --- | --- | --- |
| ECC | 101 | 0.126 | 0.42 | 0.45 | 52% | $642,428 |
| SNCR | 101 | 0.121* | 0.41 | 0.46 | 53% | $3,469,565 |
| Fuel Switching - NG | 101 | 0.118* | 0.41 | 0.47 | 54% | $509,494,272 |
| SCR | 101 | 0.061 | 0.28 | 0.59 | 68% | $20,548,387 |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "PRPA Modeling Summary" for more details.

Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

# RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE) SOURCE CATEGORY

**NOx Emission 4-Factor Analysis for Reasonable Progress (RP)**

## I. Source Description

The review of potential RP sources involved an evaluation all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. There were one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants which were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I Area (CIA) boundary. The Q/d was calculated for each source, where "Q" is the sum of the SO2, NOx and PM10 emissions in tons per year and "d" is the source distance from the nearest CIA in kilometers; which resulted in the identification of seventeen (17) point sources with a $Q/d \geq 20$. The Q/d threshold was determined based on conducting a sensitivity analysis of previous subject-to-BART CALPUFF modeling of BART eligible sources that indicated a value of 20 represented about 0.3 deciview of change in visibility impairment.

An evaluation of the 17 RP sources identified only one source directly associated with RICE equipment, a compressor station (Ignacio B Plant) that uses natural gas-fired RICE. The Ignacio B compressor station is located southeast of Durango on Southern Ute Indian Tribal land which is outside the jurisdiction of the State of Colorado; consequently the Division is unable to provide a 4-factor NOx control evaluation and associated determination for this particular RP source.

In addition to individual point sources with a $Q/d \geq 20$, the Division evaluated categories of sources that were determined to be significant and subject to evaluation under RP. The Colorado point source emission inventory indicates that stationary internal combustion engines (see below table), particularly large industrial natural gas fired reciprocating internal combustion engines (RICE), are a significant source category of NOx emissions that represents about 16% of statewide point source NOx emission inventory[1].

Colorado Internal Combustion Engine NOx Emissions from the PRP 2018b Emission Inventory

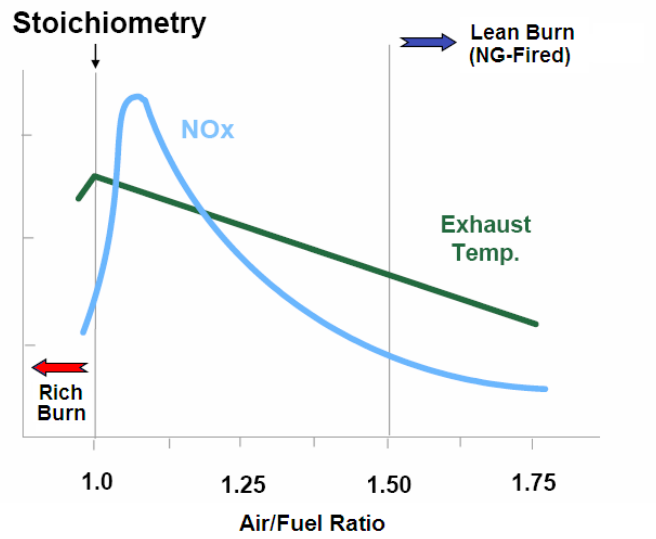
| Category | Subcategory | 2018 NOx Emissions (tpy) |
|---|---|---|
| Industrial | Natural Gas Fired | 16,199 |
| | Large Bore Engine | 256 |
| | Distillate Oil (Diesel) | 225 |
| | Liquefied Petroleum Gas | 27 |
| | Gasoline | 24 |
| Electric Generation | All | 4,323 |
| Commercial/Institutional | All | 1,152 |
| Engine Testing | All | 5 |
| | Total: | 22,210 |

[1] Total 2018 Statewide Point Source NOx is projected at 101,818 tons per year based on the WRAP PRP2018b emission inventory.

The majority of the RICE operating in Colorado are associated with the oil and gas industry. The power generated by these RICE is generally used to compress natural gas for line transmission or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this document.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios (AFR). If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. An air-to-fuel ratio controller uses exhaust $O_2$ to control the combustion ratio. RICE that are operated with fuel-rich ratios (exhaust $O_2 < 0.05\%$) at or near stoichiometric, are called rich-burn engines (RB), or alternatively RICE that operate with air-rich ratios (exhaust $O_2 > 7$ to 8%) above stoichiometric, are called lean-burn engines (LB). The undesirable combustion emissions from natural gas fired RICE are primarily nitrogen oxides (NOx, consisting of primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). Oxides of nitrogen are formed by thermal oxidation of nitrogen from the air. CO and VOCs are byproducts of incomplete combustion.

**NOx and Exhaust Temperature Change with Air/Fuel Ratio**




There are site specific considerations for using either type of engine, depending on the parameters that are most important for the operator. RB engines have lower oxygen levels and higher temperatures in the engine exhaust, which allows for the use of a 3-way catalyst (non-selective catalyst) which is effective at reducing NOx, CO, and VOCs in the exhaust. Because the air-to-fuel ratio is rich with fuel, more fuel is used, which results in increased combustion temperatures, increased engine power, and decreased engine efficiency. Higher temperatures result in more NOx being formed during the combustion process. Conversely, LB engines have higher oxygen levels in the combustion chamber, which decreases the combustion temperature thereby reducing how much NOx is formed. Because the air-to-fuel ratio is lean with fuel, less fuel is used, which results in decreased combustion temperatures, decreased engine power, and increased engine efficiency. The use of an oxidation catalyst on a lean burn engine similarly results in decreases in CO and VOC emissions but the performance for controlling NOx

emissions is very low because LB engine exhaust temperatures are below the optimum temperature range for effective NOx control due to reduced catalyst reactivity. The above chart provides the relative change in NOx emissions and engine exhaust temperature as a function of air-to-fuel ratio.

## II. Natural Gas-Fired RICE Source Category Emissions - Statewide

Since natural gas-fired RICE comprise over 73% of the NOx emissions in statewide RICE source category, the analysis will focus exclusively on NG-fired RICE. In 2018, the statewide NG-fired RICE source category is projected to contribute the following emissions:

Statewide Natural Gas Fired RICE Source Category Emissions*

| Total Number of Sources with NG-fired RICE | Pollutant | Number Sources with RICE > 100 tpy | Number Sources with RICE > 40 tpy | Number Sources with RICE < 2 tpy | 2018 Emissions (tpy) |
|---|---|---|---|---|---|
| 497 | NOx | 40 | 85 | 82 | 16,199 |
| | $SO_2$ | 0 | 0 | 486 | 115 |

* *Point Source Natural Gas Fired RICE Emissions based on APEN report data supplied to the WRAP for the PRP2018b Emission Inventory.*

Based on the PRP 2018b emission inventory, statewide there are about 497 sources using NG-fired RICE and about 40 sources that emit NOx emissions greater than 100 tons per year. During a recent 2008 rulemaking, the Division conducted a detailed analysis of RICE outside the 9-county metro area (referenced as "statewide") and determined that there are about 1,340 NG-fired RICE statewide[2], which includes about 593 NG-fired RICE over 500 hp as indicated in the below table.

Statewide Natural Gas-Fired RICE Over 500 Horsepower Outside the 9-County Metro Area

| SCC Description | Number of RICE |
|---|---|
| 2-CYCLE LEAN BURN (NG) | 84 |
| 4-CYCLE LEAN BURN (NG) | 204 |
| 4-CYCLE RICH BURN (NG) | 305 |
| Total: | 593 |

In addition to the 593 RICE listed above, the 2004 Denver Early Action Compact rulemaking identified 139 NG-fired RICE[3] over 500 hp that were subject to control requirements of non-selective catalytic reduction on 79 RB RICE and oxidation catalyst on 60 LB RICE in the 9-county metro area. Consequently, there are a total of 732 NG-fired RICE over 500 hp in Colorado.

It is difficult to readily determine the exact number of NG-fired RICE below 500 hp but over 100 hp because engines were sometimes grouped together in a single permit. However, a preliminary review of APEN data indicates that there are approximately 234 NG-fired RICE below 500 hp but over 100 hp. The remaining 513 NG-fired RICE have design capacities under 100 hp.

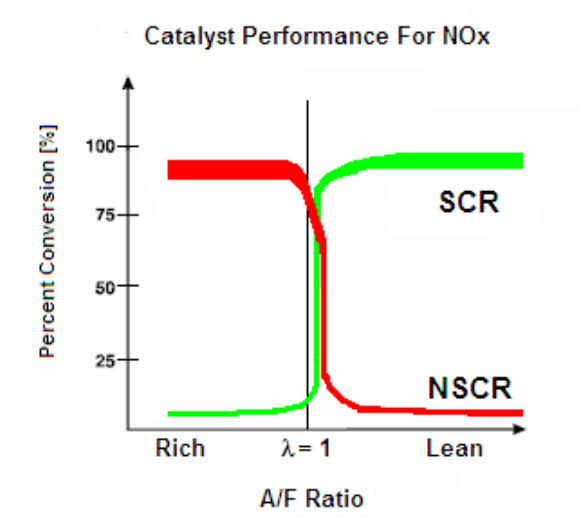
[2] The Statewide RICE count does not include RICE in the 9-county metro area which was subject to an earlier rulemaking, thus the actual number of total RICE in the State of Colorado is higher.

[3] Reference Final Economic Impact Analysis – Revisions to Regulation No. 7, February 11, 2004.

## III. NOx Control Technology Evaluation

Step 1: Identify All Available Technologies

Generally in retrofit applications, NOx emissions from engines can be reduced either through combustion controls or adding post combustion emission controls (e.g., catalysts) to the engine exhaust. Catalysts are designed to speed up desired reactions. The rate of chemical reaction is a function of several parameters, including air-to-fuel ratio, engine load and exhaust temperature. Catalysts have specific temperature ranges that must be achieved for optimum NOx reduction. The below diagram roughly depicts the catalyst performance for conversion of NOx emissions using a NSCR and SCR on rich and lean burn engines.




Six retrofit technologies have been identified to lower NOx emissions from rich/lean burn natural gas-fired internal combustion engines.

1. Lean Burn – Air/Fuel Ratio Adjustment
2. Lean Burn – Ignition or Spark Timing Retard
3. Rich Burn – Non Selective Catalytic Reduction (NSCR) Catalyst (3-way)
4. Rich/Lean Burn – Selective Non-Catalytic Reduction (SNCR)
5. Lean Burn – Selective Catalytic Reduction (SCR)
6. Replacement with electric motors

Colorado requires that emissions from rich burn RICE (applicable statewide[4]) be controlled using a 3-way catalyst (NSCR) with air/fuel controller if control costs are below $5,000 per ton. Few of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concludes that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide. Therefore, the following analysis does not evaluate lower benefit NOx controls such as air/fuel adjustment or ignition/spark timing adjustment for rich burn RICE despite the technical feasibility of such controls.

[4] Reference Colorado Regulation Number 7, see section XVII.E.3.a

It is important to clarify that lean burn RICE are not subject to NOx retrofit controls because Regulation 7 requires statewide lean burn RICE over 500 HP to install retrofit oxidation catalyst control, which is only effective for control of VOC and CO, if the VOC control cost is under $5,000 per ton. This Regulation was effective as of July 1, 2010.

Step 2: Eliminate Technically Infeasible Options

*Technology #1 - LB (Air/Fuel Ratio Adjustment): This technology is technically feasible.*

*Technology #2 - LB (Ignition/Spark Timing Retard): This technology is technically feasible.*

*Technology #3 – RB (3-way NSCR Catalyst): This technology is technically feasible.*

*Technology #4 – RB/LB (SNCR): This technology is technically feasible.*

*Technology #5 – LB (SCR): This technology is technically feasible.*

*Technology #6 – Replace RICE with electric motors: This technology is technically feasible.*

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

*Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment):* In lean burn engines, increasing the air to fuel ratio decreases the NOx emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NOx formation. In order to avoid de-rating, combustion air to the engine must be increased at constant fuel flow, requiring a turbocharger. An automatic air-to-fuel ratio controller also will be required. This control method is most effective on fuel-injected engines. Typically, for lean burn engines the air/fuel ratios are increased from normal levels of 50% excess air up to excess air levels of 240%. The upper limit is constrained by the onset of misfiring at the lean limit. This condition also increases CO and VOC emissions. Naturally aspirated engines and engines with fuel injected into the intake manifold plenum do not have identical air-to-fuel ratios in each cylinder, this results in limited ability to vary the A/F ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions. On lean burn RICE, air/fuel ratio adjustment generally achieves about 5-30% reduction[5] in NOx emissions but is very specific to each engine and typical loading.

*Technology #2 - Lean Burn (Ignition/Spark Timing Retard):* This adjustment lowers NOx emissions by moving the ignition event to later in the power stroke. Because the combustion chamber volume is not at its minimum, the peak flame temperature will be reduced, thus reducing thermal NOx formation. Ignition timing retard is applicable to all engines. It is implemented in spark ignition engines by changing the timing of the spark, and in compression ignition engines by changing the timing of the fuel injection. For variable loads, an electronic ignition/injection control system is required. On lean burn RICE, ignition/spark timing retard generally achieves about 20% reduction in NOx emissions.

*Technology #3 - Rich Burn NSCR:* This technology uses three-way catalysts to promote the reduction of NOx to nitrogen and water. CO and hydrocarbons are simultaneously oxidized to carbon dioxide and water. NSCR is applicable only to rich burn engines (i.e. those with exhaust oxygen concentration below about one percent). NSCR, in addition to the catalysts and catalyst

[5] Reference – State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

housing, require an oxygen sensor and automatic air to fuel ratio controller to maintain an appropriate air to fuel ratio. Some ammonia can be produced particularly as the catalyst ages. The simplified reactions governing NSCR are as follows:

$$NOx + CO \rightarrow CO_2 + N_2$$
$$NOx + HC \rightarrow CO_2 + H_2O + N_2$$

The exhaust passes over a catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20. Typical exhaust temperatures for effective removal of NOx are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness typically around 80 to 90 percent NOx control. Extremely tight control of the air to fuel ratio operating range is accomplished with an electronic air to fuel ratio controller.

*Technology #4 - Rich/Lean Burn SNCR:* SNCR is applicable to both lean burn natural gas and diesel engines. SNCR involves injecting ammonia or urea into regions of the exhaust with temperatures greater than 1200 – 2000 degrees Fahrenheit. The nitrogen oxides in the exhaust are reduced to nitrogen and water vapor. Additional fuel is required to heat the engine exhaust to the correct operating temperature. Heat recovery from the engine exhaust can limit the additional fuel requirement and concurrent additional emissions from heating exhaust gases. Ten parts per million of ammonia (slip) is considered reasonable for SNCR. Temperature is the operational parameter affecting the reaction - as well as degree of contaminant mixing with reagent and residence time. Additional control of particulate matter (up to 85% diesel particulate matter), volatile organic compounds (up to 90 percent) and carbon monoxide (up to 70 percent) may be realized by the afterburning effect of this technology. On both rich burn and lean burn RICE, SNCR generally achieves about 50 to 95% reduction in NOx emissions.

*Technology #5 – Lean Burn SCR:* SCR uses catalyzed reduction of NOx with injected ammonia or urea solution. This technology is applicable to lean burn engines only (i.e., those with greater than about one percent exhaust oxygen, as oxygen is a reagent in the selective reduction reaction.) SCR may be used with lean burn (SI), dual fuel or diesel engines (CI). SCR produces unreacted ammonia (slip) and monitors are necessary to provide correct control of ammonia injection rates to minimize slip. When used with diesel engines, it is important to use a low sulfur fuel and sulfur resistant catalyst. Sulfur dioxide in the exhaust can be oxidized over the SCR catalyst to sulfuric acid mist, and when combined with unreacted ammonia, produces sulfate particulate.

For an SCR system using urea, the first stage of the catalyst bed is the hydrolysis catalyst, which converts the urea to ammonia. In the second stage of the catalyst, the ammonia and NOx react to form nitrogen gas and water with some unreacted ammonia passing through. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450°F and 800 °F. For higher temperatures (675 °F to 1100 °F), zeolite catalysts may be used. Both the base metal and zeolite catalysts are sulfur tolerant for diesel engine exhaust. Precious metal SCR catalysts are useful for low temperatures (350 °F to 550 °F). When using precious metal SCR catalysts, attention should be paid to the fuel sulfur content and the appropriate formulation selected. This is not a concern with RICE fired with natural gas.

Reactions of NOx over SCR catalyst:

$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$
$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O$
$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$

An SCR system consists of reagent storage, feed and injection system, and a catalyst and catalyst housing. Predictive mapping of engine operating parameters can be used to monitor and control the SCR reaction. Precious metal catalysts can reduce NOx by 80%. Zeolite catalysts can reduce NOx by 90% with minimal sulfur dioxide to sulfur trioxide conversion. Exhaust gas temperatures greater than the upper limit (850 F) will pass the NOx and ammonia unreacted through the catalyst.

*Technology #6 – Replace RICE with electric motors:* This control technology results in complete reduction of NOx emissions at the RICE location, although the electric power provided to the motor must be supplied by a power plant located at some distant location. There is a net reduction in NOx emissions from consolidating operations although the amount of reduction depends on the distance from the power plant as transmission line losses reduce the effectiveness of this control. Another consideration is the proximity to high voltage lines which may limit the practically of this control option in rural areas.

The below table summarizes each available technology and the technical feasibility for NOx Control.

NG-Fired RICE – NOx Technology Options and Technical Feasibility

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| *Lean Burn (Air/Fuel Ratio Adjustment)* | ~5-30% | Y |
| *Lean Burn (Ignition/Spark Timing Retard)* | ~20% | Y |
| *Rich Burn NSCR* | ~80-90% | Y |
| *Rich/Lean Burn SNCR* | ~50-95% | Y |
| *Lean Burn SCR* | ~80-90% | Y |
| *Replace RICE with electric motors* | ~60-100% | Y |

Step 4: Evaluate Impacts and Document Results

**Factor 1: Cost of Compliance**

*Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment):* In naturally aspirated LB engines and LB engines where fuel is injected into the intake manifold plenum, each cylinder does not have an identical air-to-fuel ratio, thus changes in the A/F ratio are very limited and therefore of little benefit, although the cost of such adjustment is minimal. Additional NOx emission reduction benefit is gained through the addition of a turbocharger and an automatic air-to-fuel ratio controller. The cost of adding these controls is very specific to the engine size and design but generally ranges between $320 to $8,300 per ton[6] of NOx reduced.

[6] Reference – Supplementary Information for Four Factor Analysis by WRAP States, EC/R Incorporated, May 4, 2009, see table 3-3.

*Technology #2 - Lean Burn (Ignition/Spark Timing Retard):* Based on a general analysis of NG fired RICE for the WRAP states[4], the cost of this control ranges between $310 to $2,000 per ton of NOx depending on engine size and firing design.

*Technology #3 - Rich Burn NSCR:* Regulation Number 7 requires rich burn RICE over 500 HP to install retrofit NSCR controls if the cost of control is under $5,000 per combined ton (NOx and VOC) statewide. This Regulation was effective as of July 1, 2010. None of the operators of rich burn RICE outside the metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller.

Emission Reduction from NSCR Retrofit of RICE > 500 hp

| Statewide RICE Category* | Count** | $NO_x$ Reduction (tpy) |
|---|---|---|
| Lean Burn ≥ 500 HP | 288 | minimal*** |
| Rich Burn ≥ 500 HP | 305 | 5,800 |

Notes:

* This data represents statewide RICE, excluding the 9-county metro area (ozone non-attainment area) which was addressed in an earlier rulemaking for the Early Action Compact.

** Data obtained from 2008 APENs

*** Retrofit NSCR for lean burn RICE was not required because of minimal NOx reduction

Annualized Costs for Rich Burn RICE Control Device

| Item | Capital Costs (one time) | O&M (recurring) | Total Annualized Cost (15 yrs) |
|---|---|---|---|
| NSCR with AFR Controller* | $35,000 | - | |
| Operating | - | $6,000 | |
| Subtotal Costs: | $35,000 | $6,000 | |
| | | | |
| Annualized Costs: | $4,851 | $6,000 | **$10,851** |

Notes:

* Cost estimates obtained from "Denver Early Action Compact Analysis of Stationary Sources" Nov. 3, 2003

Costs Associated with Statewide Retrofit of Natural Gas-fired RB RICE ≥ 500 HP

| Category | Number of Devices | Annualized Cost per Device | Total Device Cost | $NO_x$ Reduction [tpy] | $/ton |
|---|---|---|---|---|---|
| NSCR & AFR Controller | 305 | $10,851 | $3,309,555 | 5,800 | $571 |

*Technology #4 - Rich/Lean Burn SNCR:* SNCR usually requires reheating of the exhaust to achieve the proper temperature range for effective NOx conversion; this is particularly true for lean burn RICE where excess oxygen results in exhaust temperatures well below the required levels. The Division was unable to acquire cost information for this control option, thus no cost estimates have been provided. The scarcity of SNCR data on NG-fired RICE may suggest other post combustion NOx controls are preferred, particularly SCR which has more reliable control effectiveness under a variety of load conditions.

*Technology #5 – Lean Burn SCR:* Depending on the engine size, catalyst used and the level of sophistication of the control system, SCR costs generally range about $430 to $4,900 per ton of NOx reduced.

*Technology #6 – Replace RICE with electric motors:* Depending on the engine size, length and capacity of the power line required, the costs generally range from $100 to $4,700 per ton of NOx reduced[7]. These costs do not include any potential impact from increases in electrical load at the power plant. The true cost of replacing RICE with electric motors is dependent on the distance from the power plant and the amount of compression power required. In actuality, larger compressor stations with multiple large engines would produce significant increased demands at a nearby power plant and possibly significant demands on the line transmission system that would escalate the costs to levels much higher than the $4,700 control cost. Colorado has about 40 large compressor stations, thus the estimation of costs would require a case-by-case analysis which was not done for this RP evaluation. Although, if all statewide RICE (above 500 horsepower) were converted to electric motor compression, then a minimum of approximately 600 MW of extra generating capacity would be required. Realistically, the actual generating capacity required is probably much higher when transmission losses and peak demand cycles are factored into the load demands.

**Factor 2: Time Necessary for Compliance**

*Technology #1, 2, 4, 5 and 6:* If Colorado was to decide to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules and undergo Legislative review. Subject sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NOx control[8]. However, the time necessary will depend on the type and size of the unit being controlled. For instance, in past rulemakings, typically 18 months may be required to install a particular control technology on hundreds of engines. Additional time, up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve the NOx emission reductions for reciprocating engines is estimated at about 5 years.

*Technology #3:* This control option is implemented and was effective on July 1, 2010.

**Factor 3: Energy Impacts and Non Air-Quality Impacts**

In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value[9] of about 2.5%. This increased fuel consumption would result in increased $CO_2$ emissions. Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed. This would produce an increase in $CO_2$ emissions. In addition, spent

[7] Bar-Ilan, Amnon, Ron Friesen, Alison Pollack, and Abigail Hoats (2007), *WRAP Area Source Emissions Inventory Protection and Control Strategy Evaluation - Phase II*, Western Governors Association, Denver, Colorado, Chpt 4.

[8] Institute of Clean Air Companies (2006), Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources.

[9] Center for Alternative Fuels, Engines & Emissions (2005), Alice Austen Ferry Emissions Tests, M.J. Bradley & Associates, Manchester, NH, Page 13.

catalyst would have to be changed periodically, producing an increase in solid waste disposal[10]. Replacing RICE with electric motors may require construction of additional power plants to accommodate increased power demands.

**Factor 4: Remaining Useful Life:**

Generally the operational life of a catalyst is approximately 5 to 15 years, depending upon factors such as how it is maintained and the particular duty cycle of the engine.

Step 5: Select Reasonable Progress Control

The state has determined that control technology #3, rich burn NSCR w/air-fuel controller, represents reasonable progress for the natural gas-fired RICE source category in this planning period. The estimated reduction of 5,800 tons/year represents about 36% of the NG RICE total NOx emissions.

The State of Colorado regulates RICE under Colorado Air Quality Control Commission Regulation No. 7 (Reg. 7) Section XVII. Further NOx emission reduction benefits are anticipated in the future because of tighter NOx emission standards in Regulation 7 that require emissions from RICE shall not exceed the following emission performance standards:

Colorado Emission Standards Natural Gas-Fired RICE

| RICE Horsepower | Construction or Relocation Date | Emission Standards (grams/hp-hr) | | |
|---|---|---|---|---|
| | | NOx | CO | VOC |
| < 100 | Any | NA | NA | NA |
| ≥ 100 and ≤ 500 | On or after 1/1/08 | 2.0 | 4.0 | 1.0 |
| | On or after 1/1/11 | 1.0 | 2.0 | 0.7 |
| > 500 | On or after 7/1/07 | 2.0 | 4.0 | 1.0 |
| | On or after 7/1/10 | 1.0 | 2.0 | 0.7 |

RICE that are subject to an emissions control requirement in a federal Maximum Achievable Control Technology (MACT) standard under 40 CFR Part 63, a Best Achievable Control Technology (BACT) limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to Reg. 7 Section XVII.

[10] EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit OO: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023)

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Notice of confidentiality.
A portion of this document has been filed under seal.
Confidential information has been redacted from page 44.



Hearing Exhibit 101
LKT-1 - Attachment G-1 - Public - ELCC and PRM Study (Astrape)
Proceeding No. 23A-0585E
Page 1 of 68

ASTRAPÉ CONSULTING
innovation in electric system planning

# Reserve Margin and Effective Load Carrying Capability (ELCC) Study

## Final Report

8/02/2023

PREPARED FOR

*Tri-State G&T*

PREPARED BY

*Astrapé Consulting*

Colorado PUC E-Filings System

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# ABBREVIATIONS USED IN REPORT

| | |
|---|---|
| BAA | Balancing Authority Area |
| BE | Better Electrification |
| BESS | Battery Energy Storage System |
| BTMPV | Behind the meter solar |
| CEII | Critical Energy/Electric Infrastructure Information |
| CT | Combustion Turbine Generator |
| DR | Demand Response |
| EE | Energy Efficiency |
| EFOR | Equivalent Forced Outage Rate |
| EFORd | Equivalent Forced Outage Rate Demand |
| EIA | Energy Information Administration |
| ELCC | Effective Load Carrying Capability |
| FERC | Federal Energy Regulatory Commission |
| GADS | Generating Availability Data System |
| GDP | Gross Domestic Product |
| ICAP | Installed Capacity |
| ILR | Inverter Loading Ratio |
| IRP | Integrated Resource Plan |
| LFE | Economic Load Forecast Error |
| LOLE | Loss of Load Expectation |
| MW | Megawatt |
| NOAA | National Oceanic and Atmospheric Administration |
| NREL | National Renewable Energy Laboratory |
| NSRDB | National Solar Radiation Database |
| ORDC | Operating Reserve Demand Curve |
| PCAP | Perfect Capacity |
| PO | Planned Maintenance Outage |
| PRM | Planning Reserve Margin |
| TTF | Time to Fail |
| TTR | Time to Repair |
| UCAP | Unforced Capacity |
| SAM | NREL System Advisory Model |
| SERVM | Astrapé's Strategic Energy and Risk Evaluation Model |

# EXECUTIVE SUMMARY

This document provides details concerning a two-fold study performed by Astrapé Consulting for Tri-State Generation and Transmission Association (TSGT) to accomplish the following goals:

1. Determine the Planning Reserve Margin (PRM) for TSGT's 2023 Electric Resource Plan (ERP).
2. Determine the Effective Load Carrying Capability (ELCC) for a range of solar, wind, and Battery Energy Storage System (BESS) penetrations for the TSGT system.

The following summarizes the results of this study.

## BASE CASE PRM RESULTS

The PRM of a system represents the amount of additional capacity in excess of forecasted peak load that a system would need in order to maintain an acceptable level of system reliability. The PRM was calculated using two different accounting methods, including:

1. ICAP – Traditional resources at Installed Capacity (ICAP) with renewable and other limited resources at their ELCC.
2. UCAP – Traditional resources at their Unforced Capacity (UCAP) with renewable and other limited resources at their ELCC.

The development of the PRM was accomplished by determining the amount of capacity that would be necessary to maintain a Loss of Load Expectation (LOLE) of 0.1 days/year. This level of reliability corresponds to an expectation of one day of loss of load every 10 years, which is consistent with industry practice. The advent of renewable and battery technologies has sparked conversation on the appropriateness of this metric since limitations on dispatchability and constraints on energy will likely affect the duration and depth of loss of load events. In prior work, Astrapé has found that renewable and storage resources generally have offsetting effects on the duration and depth of events and the 0.1 LOLE standard is expected to yield a relatively consistent relationship with most reliability metrics for a range of technology resource mixes. However, it will be important to continue to monitor these metrics and recommend changes to reliability standards if the nature of reliability events does change.

The PRM was developed using Astrapé's Strategic Energy and Risk Evaluation Model (SERVM). A detailed description of the methodology can be found in the Study Approach and Results section of this report. The PRM is the result of an evaluation of the probabilistically weighted LOLE across 42 weather year scenarios, five load forecast error scenarios, and hundreds of unit outage iterations. The PRM for the base case and most of the sensitivities were performed for the 2030 study year. The base case and its underlying assumptions are described in more detail in the Model Development section of this report.

Figure ES 1 below shows the result of the LOLE analysis for 2030. The figure shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE point occurs at a reserve margin of ~35.9%.

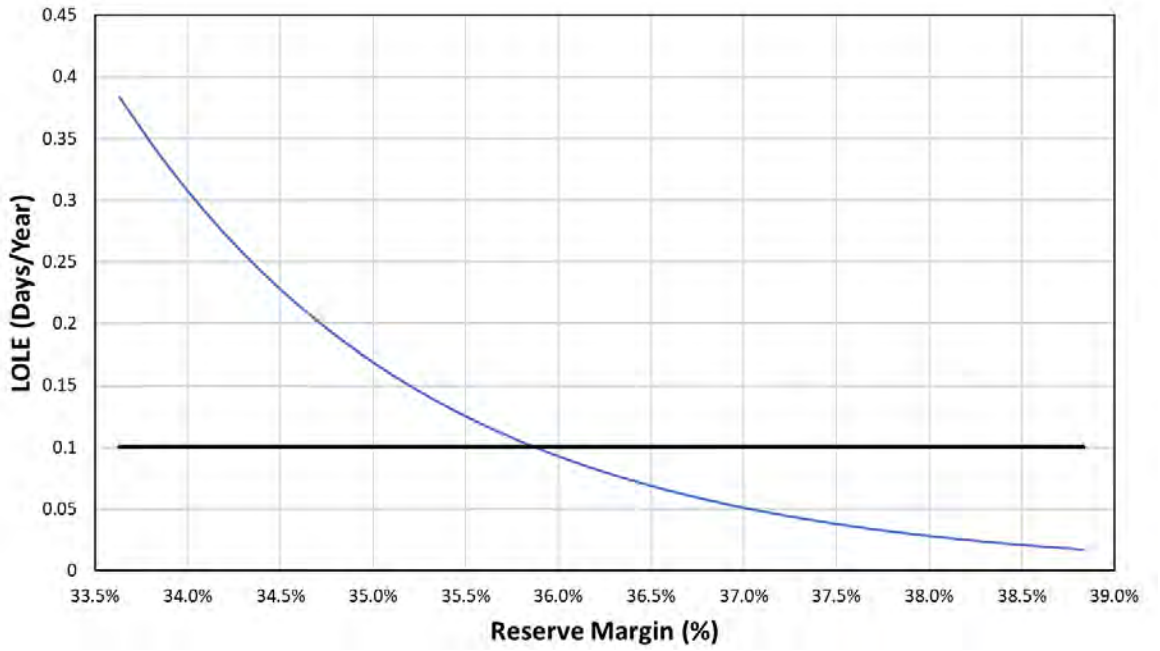


***Figure ES 1. 2026 Base Case LOLE Analysis***

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

The table below shows the ICAP accounting for the base case scenario.

***Table ES 1. Base Case ICAP PRM Accounting***

| Component | Capacity | ELCC | Equivalent Capacity |
|---|---|---|---|
| **Conventional Resources** | 2596.3 | | 2596.3 |
| **ELCC Resources** | 1934.0 | 18% | 348.1 |
| **Adjustment Capacity** | | | 59.2 |
| **Total Capacity at Target Reliability** | | | 3003.6 |
| **Coincident Peak Load** | | | 2210.9 |
| **Reserves** | | | 792.8 |
| **ICAP PRM** | | | 35.9% |

The "Adjustment Capacity" represents the amount of additional capacity above base case assumptions that was added to the system to achieve the 0.1 LOLE requirement. The ICAP PRM of 35.9% is considerably higher than TSGT's previous requirement of 15% for several reasons. First, in the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Second, TSGT will be losing approximately one-third of its load over the next few years as several member systems leave the system or transition to partial requirements. The result is a considerably smaller system in which shaft risk (i.e., the loss of units that are large relative to the peak load) becomes a more significant consideration than it was in the past. For example, with a prior peak of ~3000 MW the Springerville unit covered 14% of the load requirements. With a reduced peak of ~2200 MW, Springerville is now covering 19% of the load. Thus, more load is concentrated on that single unit, resulting in an increase in shaft and generation risk if that unit trips or fails. A similar issue is present for the other larger units, compounding the potential shaft risk in 2030. While there may have been shaft risk previously, that risk has been magnified by the loss in peak demand. The increased shaft risk translates directly into higher PRM requirements.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system Equivalent Forced Outage Rate (EFOR) resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. An alternative accounting that attempts to stabilize the PRM by removing the effects of forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by 1-EFORd, where EFORd is the Equivalent Forced Outage Rate Demand for the conventional resources. The table below shows the base case assuming UCAP accounting resulting in a UCAP PRM of 30.5%.

***Table ES 2. Base Case UCAP PRM Accounting***

| Component | Capacity | UCAP/ ELCC | Equivalent Capacity |
|---|---|---|---|
| **Firm Resources** | | | 997.3 |
| **UCAP Resources** | 1599.0 | 92.6% | 1480.1 |
| **ELCC Resources** | 1934.0 | 18.0% | 348.1 |
| **Adjustment Capacity** | | | 59.2 |
| **Total Reliable Capacity** | | | 2884.6 |
| **Coincident Peak Load** | | | 2210.9 |
| **Reserves** | | | 673.8 |
| **ICAP PRM** | | | 30.5% |

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and are achieved with identical portfolios. The only difference is in the accounting treatment of various resources.

As part of the base case PRM calculation, the ELCC of the conventional resources were calculated to demonstrate the significance of the shaft risk. The table below shows the ELCC of the coal and CC units.

***Table 1. Coal and CC ELCC***

| Resource | EFOR | ELCC |
|---|---|---|
| **Shafer CC** | 7.8% | 64.4% |
| **Springerville Coal** | 9.2% | 63.8% |
| **Laramie River Coal** | 9.3% | 58.8% |

These ELCCs are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

***Table 2. Impact of High EFOR and Shaft Risk***

| Component | ELCC | MW | Impact |
|---|---|---|---|
| **CC** | 64.4% | 272 | 175.168 |
| **SPV** | 63.8% | 319 | 203.522 |
| **LRS** | 58.8% | 484 | 284.592 |
| **Weighted** | 61.7% | 1075 | 663.282 |
| **Target ELCC** | 90.0% | 1075 | 967.5 |
| **Impact MW** | | | 304.2 |
| **Base Case Reliable MW** | | | 3003.6 |
| **Adj for EFOR/Shaft Impact** | | | 2699.4 |
| **Coincident Peak Load** | | | 2210.9 |
| **PRM** | | | 22.1% |

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

The lower ICAP PRM of 22.1% would represent a system in which shaft risk and high EFOR has been somewhat mitigated. Since the two drivers of this increased shaft risk are the retirement of several

coal units and the departure of approximately one-third of TSGT's peak demand, it would be reasonable to assume that a transitional PRM in this range would be appropriate to use for the transition years prior to the retirement of those units and the departure of the member load.

## ELCC RESULTS

The ELCC of a renewable resource/portfolio represents the amount of dependable capacity that can be counted on by the system for resource adequacy purposes and the resource's perfect capacity equivalent. The ELCC is determined by finding the amount of perfect capacity that can replace the renewable resource/portfolio without adversely affecting system reliability. The ELCC is represented as a percent of nameplate capacity. It is calculated by dividing the amount of replacement perfect capacity by the nameplate capacity of the additional renewable resource/portfolio.

For ICAP and UCAP PRM accounting purposes, the ELCC of the base case portfolio of solar and wind resources was calculated. Those results are shown in the applicable ICAP/UCAP tables in the PRM results sections above and reflect a portfolio average ELCC of 18%.

The analysis also included the calculation of average and marginal ELCCs by technology for solar, storage, and wind up to the following maximum penetrations:

- Solar – 2,000 MW
- Battery – 1,000 MW
- Wind – 2,000 MW

The result of this analysis was a dense, three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the maximum penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

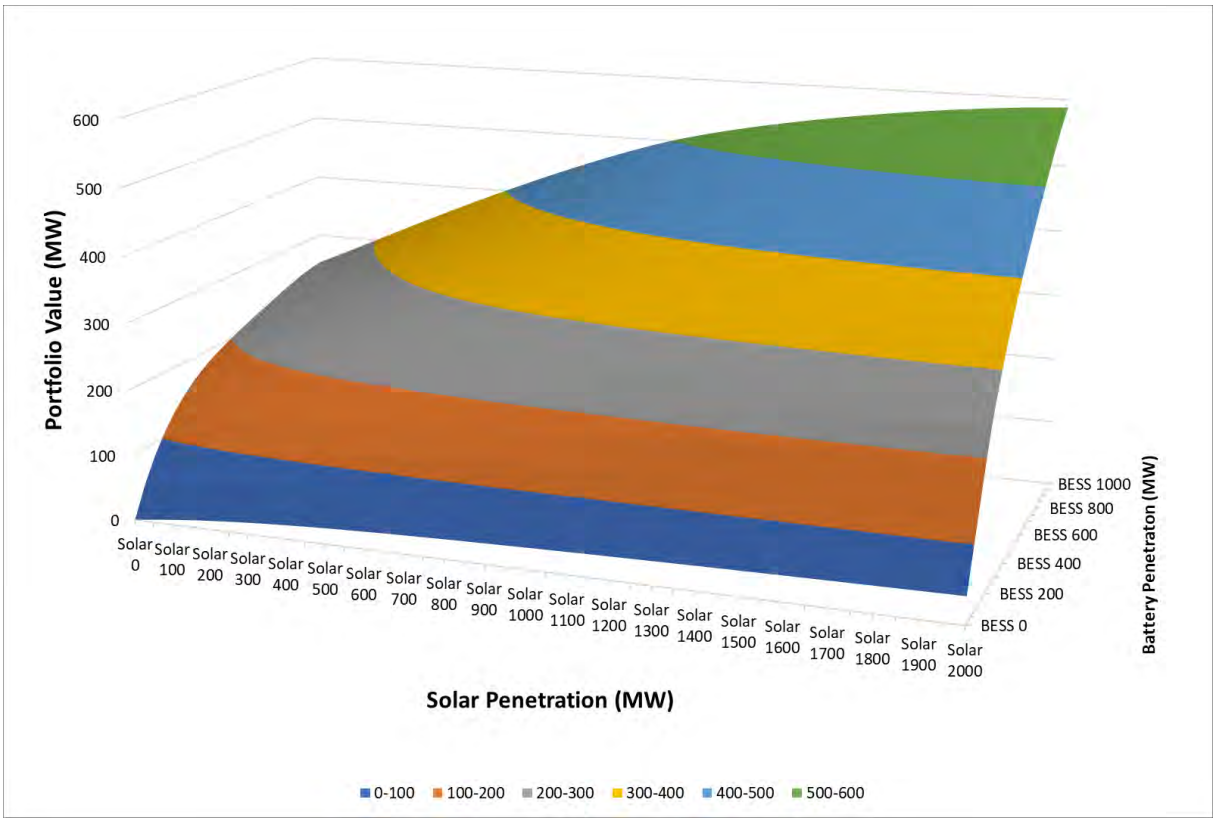


***Figure 1. Portfolio Capacity Value at Zero Wind Penetration, Illustrative***

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind:

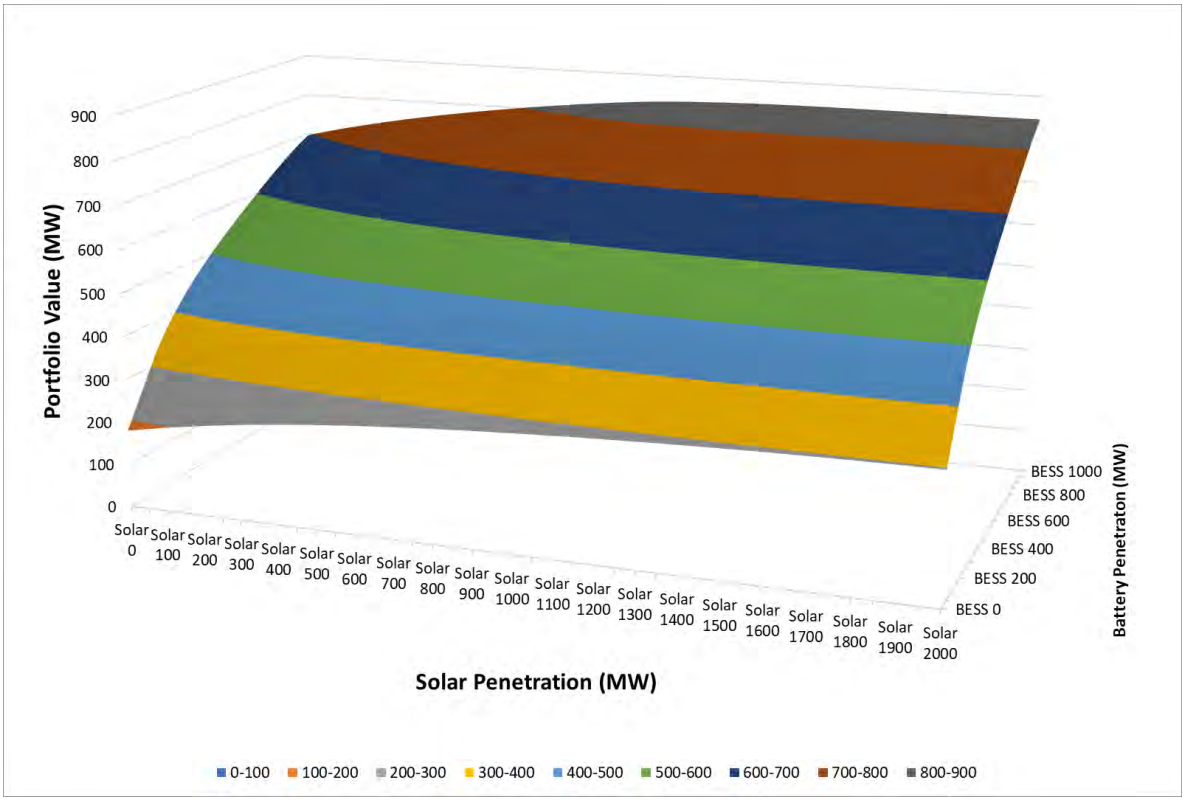


***Figure 2. Portfolio Capacity Value at 2000 MW of Wind, Illustrative***

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries (i.e., in the solar chart, wind is at 1,000 MW and batteries are at 500 MW, whereas in the battery chart, solar and wind are both at 1,000 MW).

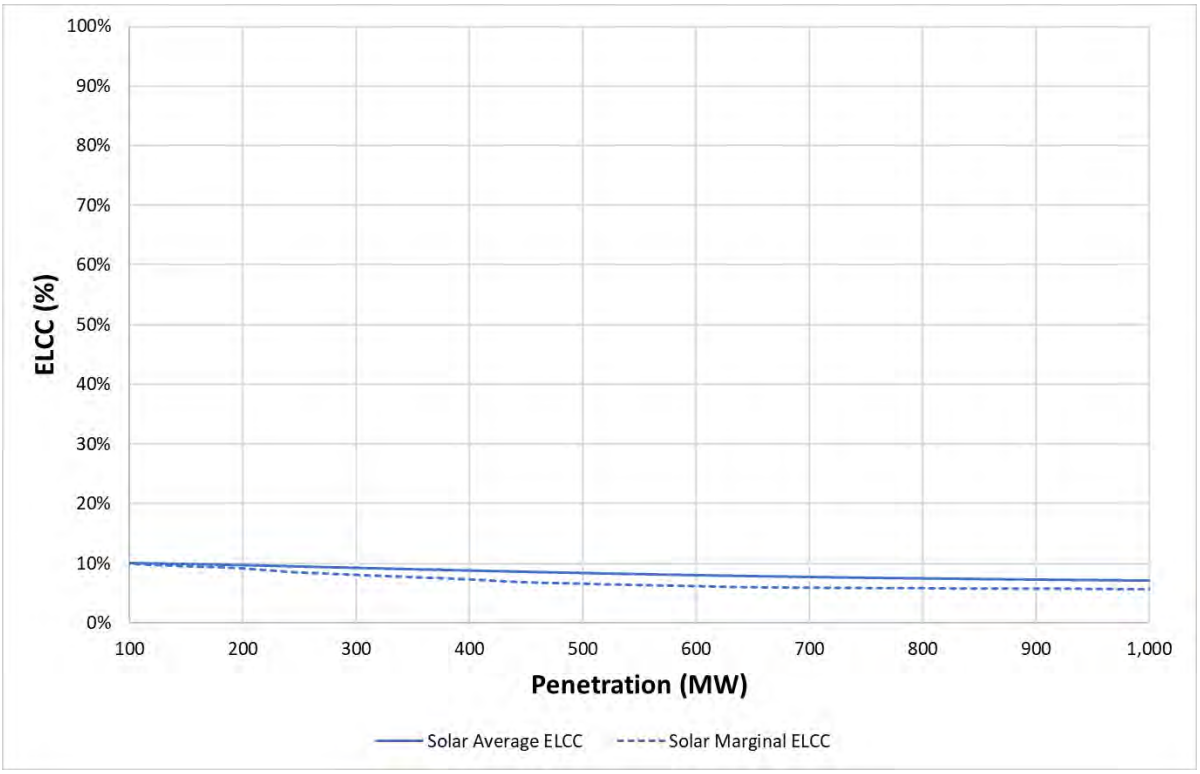


***Figure 3. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery***

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

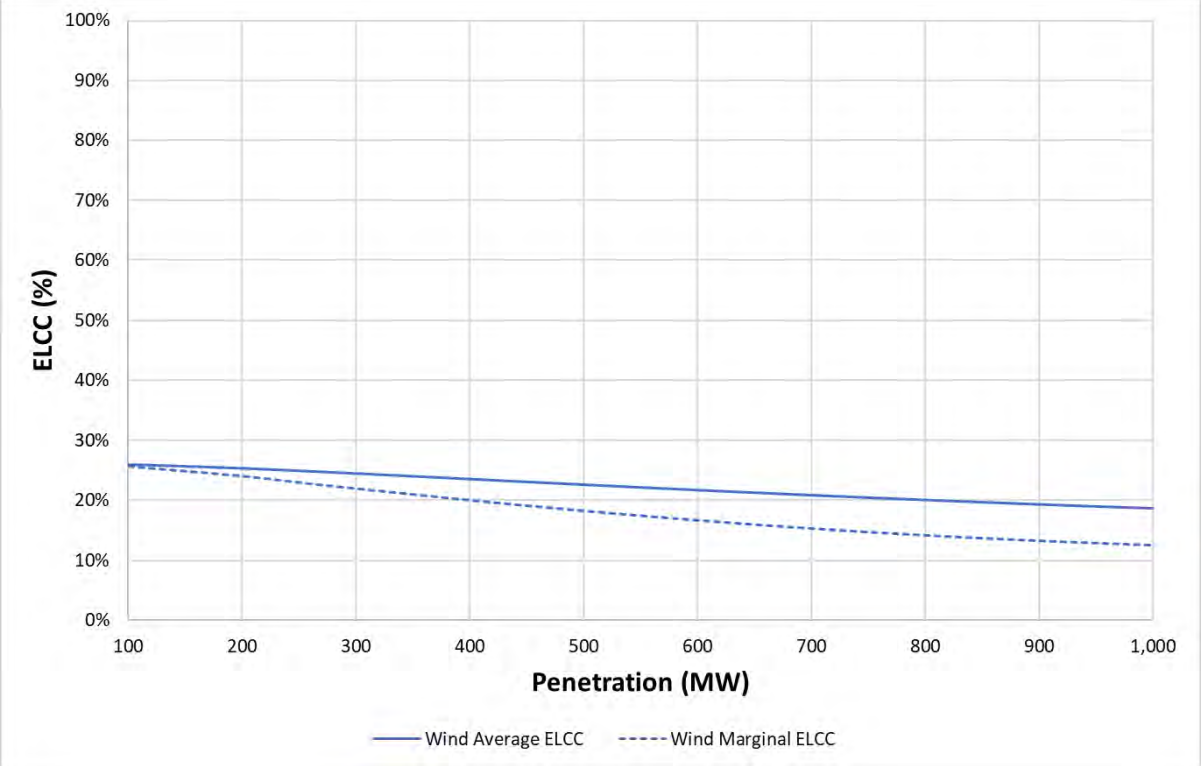


***Figure 4. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery***

Finally, the battery chart is shown below.

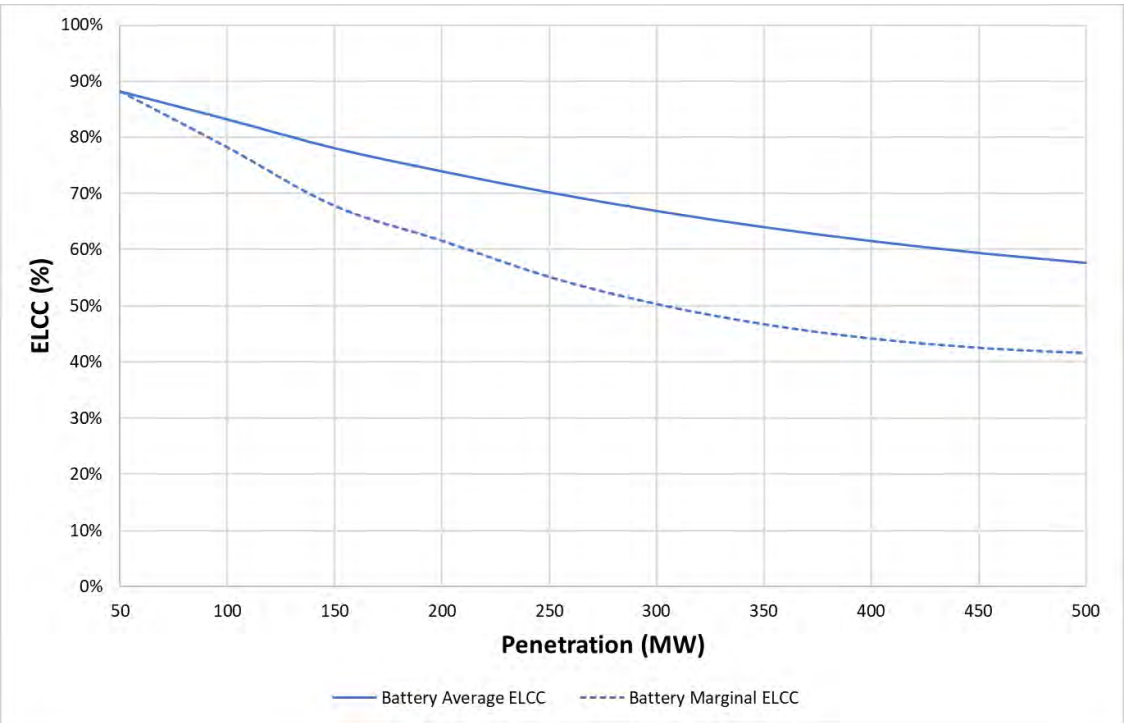


***Figure 5. Battery ELCC at 1,000 MW of Solar and Wind***

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including member system DG (not rooftop) solar, EE, and 10-hour batteries.

To determine the ELCC of the member system DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the member system DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be "first in the queue" relative to the TSGT solar. Since entity-specific capacity accreditation is not an issue for TSGT, the only concern is to get the appropriate total portfolio capacity credit for purposes of counting capacity towards meeting the reserve margin requirement. Therefore, it does not matter whether all renewable resources are considered to be added simultaneously or as was done in this analysis, some renewables were presumed to have a "first in the queue" status.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The result of this analysis is shown in the figure below.

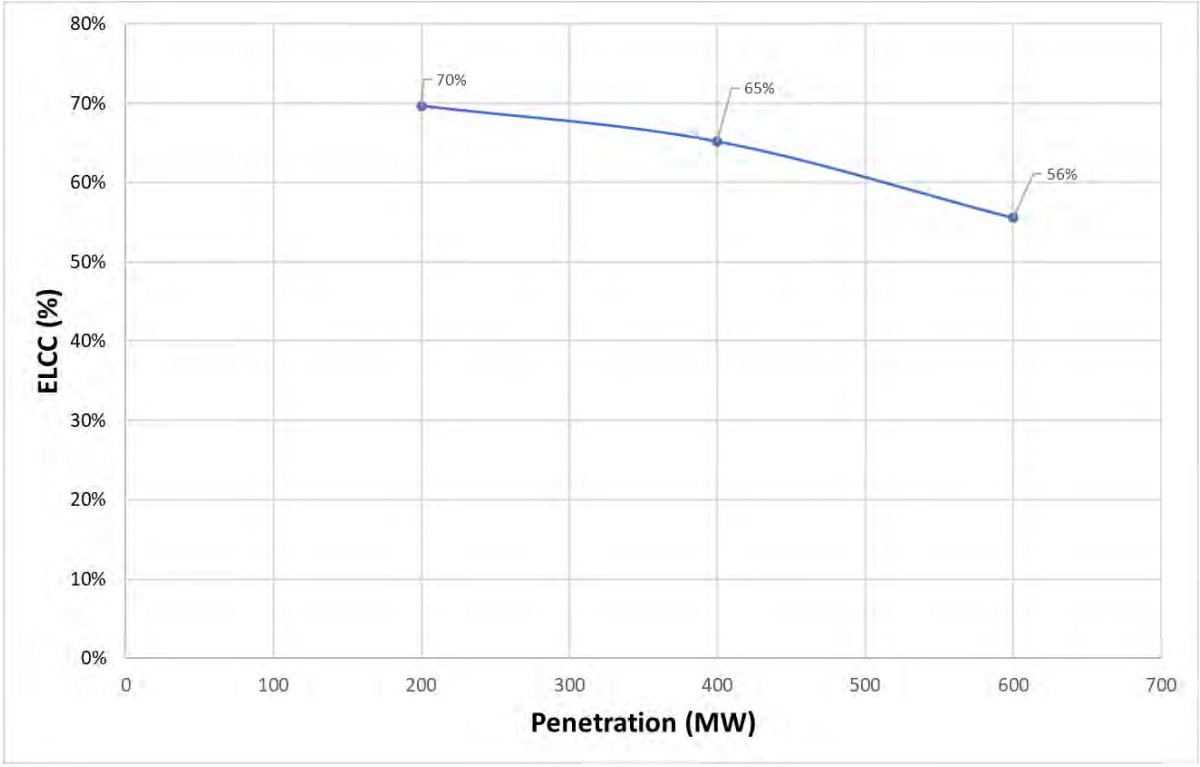


***Figure 6. 10-Hour Battery Average ELCC***

## CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

# INTRODUCTION

The purpose of this document is to describe the analysis used to determine the PRM necessary for TSGT to maintain a LOLE of 0.1 days/year or the equivalent of the common industry practice of one loss of load event in 10 years.

In addition, this document will also report on the results of a study to determine the ELCC of a series of tranches of solar, wind, and BESS resources – as well as the ELCC of several other load and resource components including customer DG solar, EE, and long duration (10-hour) batteries.

## STUDY FRAMEWORK

This study was performed using the SERVM and its associated study framework. The SERVM framework combines an hourly (i.e., 8760-hour) production cost model coupled with Monte Carlo outage simulation and comprehensive scenario management that considers load and weather uncertainty to determine key reliability parameters such as LOLE. The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

### WEATHER UNCERTAINTY

To account for weather uncertainty, SERVM performs hourly production cost simulations using multiple historical weather years. The uncertainties that are modeled for each modeled weather year include load shapes and renewable profiles. Load shapes for each weather year are developed to represent the expected future load response to the historical weather (temperatures). For example, a 1998 weather year represents how loads would respond if 1998 weather were to repeat during the given study year. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. In the case of TSGT, since their load forecast is based on the last 10 years of history, load shapes are scaled such that the median of the last 10 years equals the study year weather normal peak load forecast. Other load shapes were scaled such that their forecast matched the median of all available weather years. Similarly, renewable profiles are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 42 weather year scenarios were simulated representing weather conditions for the years 1980-2021.

### ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather normal peak load forecast associated with uncertainty in economic forecasts. Using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP), it is possible to predict both the magnitude and probability of error in the forecast of the GDP economic indicator three, four, or five years out into the future. This probability of error can then be converted into a Load Forecast Error (LFE). For this study, five LFE scenarios were chosen. These are described in the Model Development section of this document. Each of the 42 weather year scenarios are combined with each of the five LFE scenarios to create 210 unique load scenarios, or *cases*.

## MONTE-CARLO OUTAGE ITERATIONS

SERVM uses Monte-Carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 210 load cases. With each outage iteration, random Monte-Carlo draws are made to determine thermal generation outage profiles associated with that scenario. With enough iterations, the set of random outages for each thermal unit approaches that unit's expected EFOR. For this study, convergence was achieved with 200 outage draw iterations per case. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVM uncertainty framework used for this study required 42,000 hourly (8760-hour) production cost simulations for a single analytical run of the TSGT system.

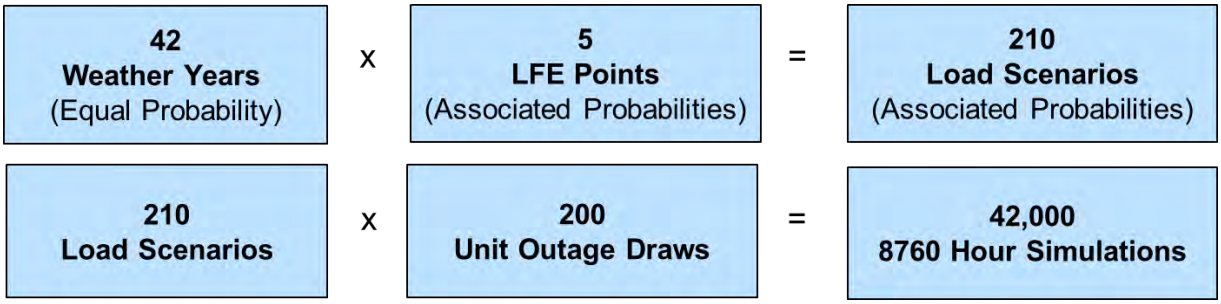


***Figure 7. SERVM Uncertainty Framework***

The Study Methodology section of this document describes the numerous "analytical runs" required to perform the reserve margin analysis, its associated sensitivities, as well as the ELCC analysis.

# MODEL DEVELOPMENT

The SERVM data model utilized for this study was based upon a joint dispatch of the four Tri-State load zones in the Western Area-Colorado Missouri (WACM), Public Service Colorado (PSCO), and Public Service New Mexico (PNM) Balancing Authority Areas (BAA). Those four load zones are Tri-State New Mexico (Tri-NM), Tri-State West Colorado (Tri-WCO), Tri-State East Colorado (Tri-ECO), and Tri-State Wyoming-West Nebraska (Tri-WYWNE). The system model also included representations of the immediate surrounding interconnected BAAs, including representations of the balance of each of the three before-mentioned BAAs, PacifiCorp East (PACE), Arizona (AZ),[1] and Southwest Public Service (SPS), which is in the Southwest Power Pool (SPP).[2] The figure below shows the configuration of the study model.

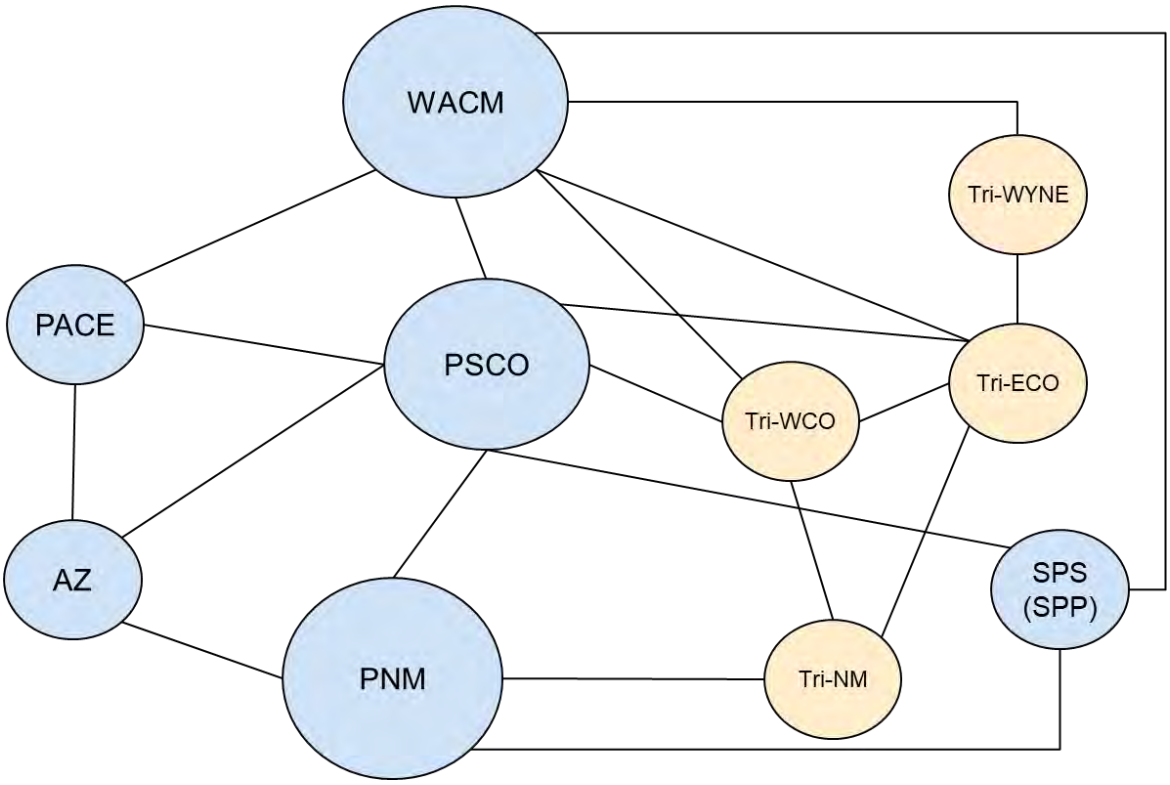


***Figure 8. System Topology***

## BASE CASE MODEL DEVELOPMENT

For the Non-TSGT regions, the SERVM database was developed using publicly available data from sources such as the U.S. Department of Energy's Energy Information Administration (EIA) Form 860, available documents from the North American Reliability Corporation (NERC), various publicly available Integrated Resource Plans (IRPs), and Federal Energy Regulatory Commission (FERC) Forms.

[1] This includes all of the entities in the Arizona Public Service BAA.
[2] SPS is across the DC ties between the Eastern Interconnect and the Western Interconnect.

The TSGT region, however, was updated using information provided by TSGT as described in the following sections.

## PEAK DEMAND FORECAST

TSGT is a wholesale provider of power to members systems consisting of rural electric cooperatives and public power districts. The TSGT official load forecast is developed based on the load from these retail service providers net of adjustments for rooftop solar resources (BTMPV). For this study, these BTMPV resources were modeled as specific resources. Additionally, incremental energy efficiency (EE) was modeled as an explicit hourly load modifier. Therefore, the TSGT forecast, which was already grossed up for incremental EE, had to be further grossed up for the impacts of the BPMPV. The figure below shows the 2030 TSGT peak demand forecast as well as the grossed up peak demand forecast used for base case modeling purposes for each of the four TSGT load zones.

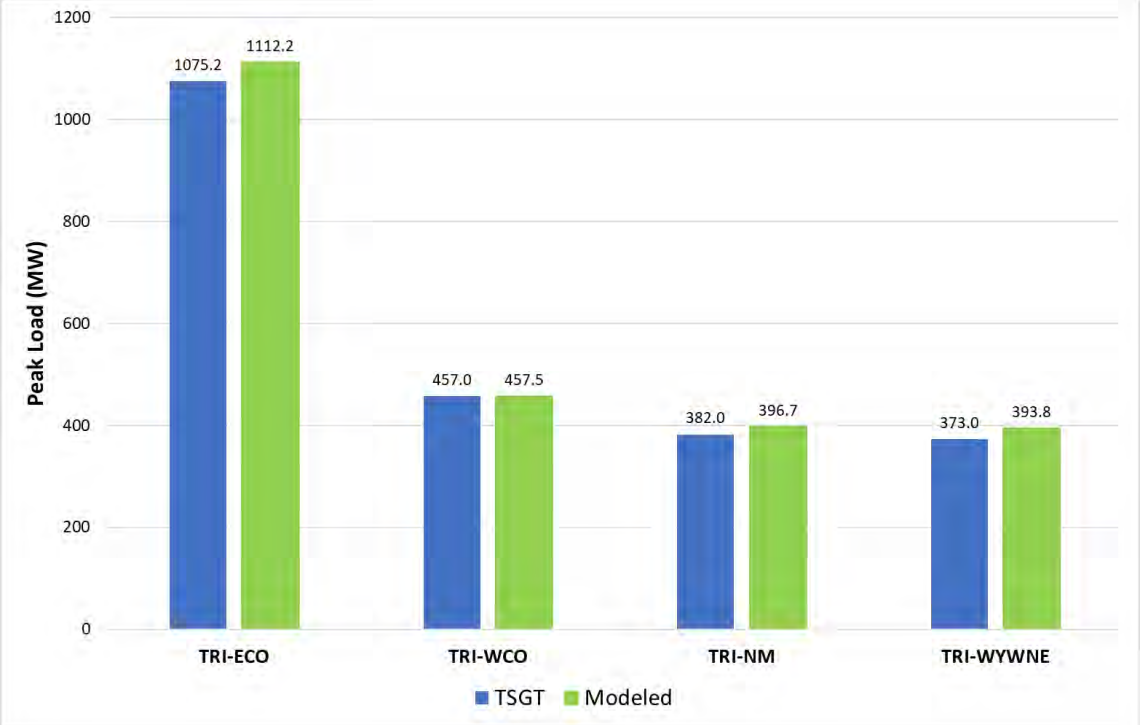


***Figure 9. 2030 Peak Demand Forecast***

The figure below shows the 2030 TSGT energy forecast as well as the grossed-up energy forecast used for modeling purposes.

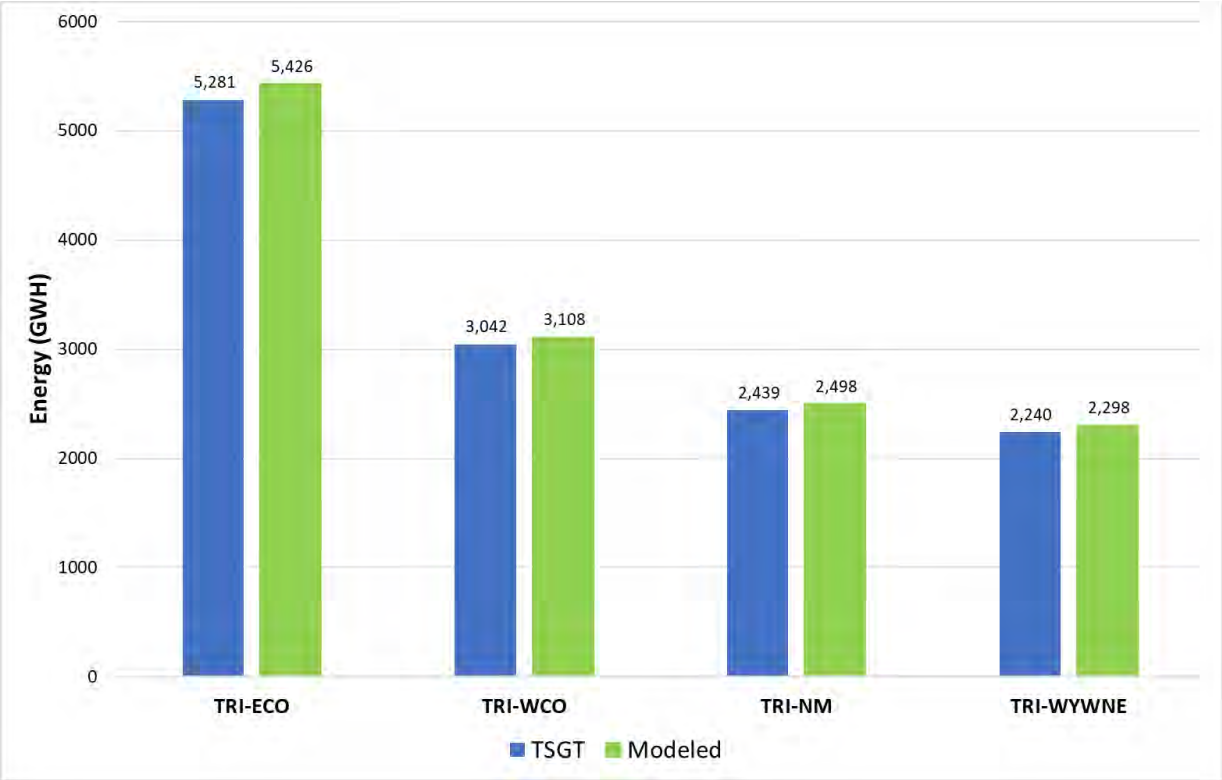


***Figure 10. 2030 Energy Forecast***

## LOAD MODELING

As described in the Study Framework subsection above, load shapes were developed for each of the 42 study years 1980-2021. These load shapes were developed based on trends and relationships between load and weather for the five historical years 2018-2022.

To prepare the loads for trending, the historical loads were grossed up for BTMPV as indicated above. The loads were further prepared by removing economic bias as well as impacts of irrigation load uncertainty. These differences were removed from the load shapes by adjusting the loads on a seasonal basis so that the highest load hours of each season were consistent across the historical period. The figure below shows an example of the result of this process. The figure shows summer weekday loads during for the Tri-WYWNE load region for hours 13-17 when temperatures were above 85°F. Loads have been adjusted to remove economic bias.

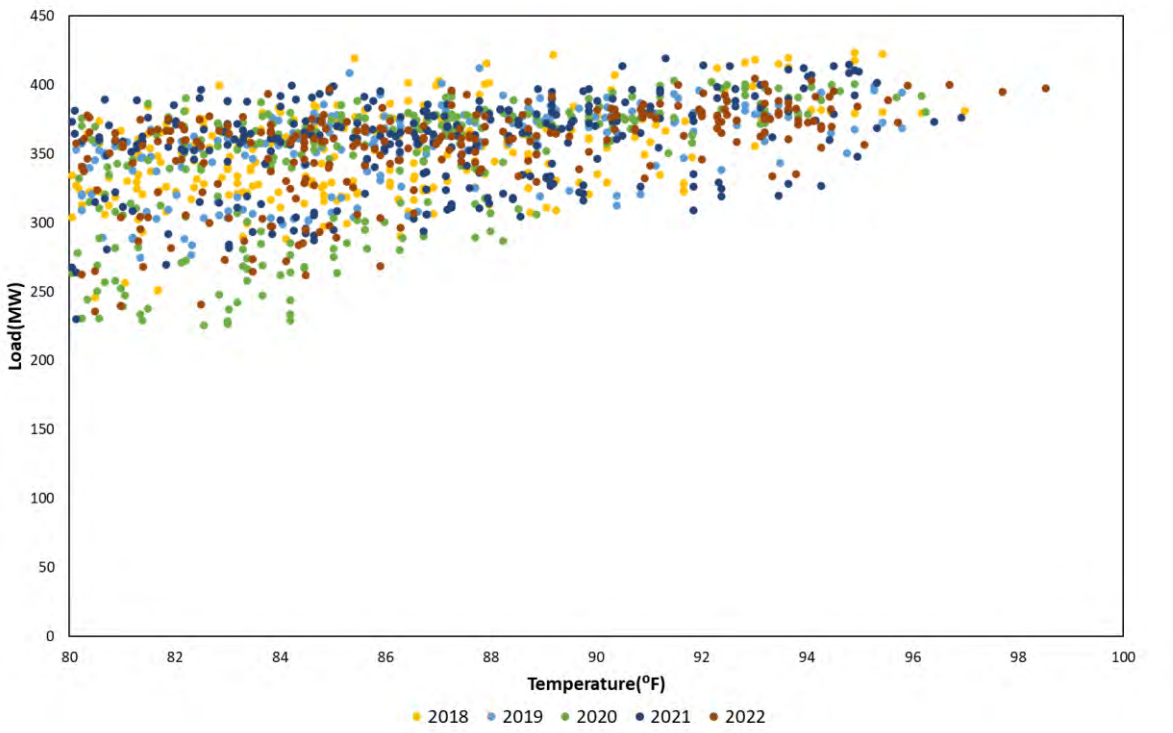


***Figure 11. Summer Peak Period Temperatures***

The five historical load shapes were trended using a neural network that was trained using hourly historical temperatures from the National Oceanic and Atmospheric Administration (NOAA) and other key variables. For trending purposes, temperatures from NOAA were downloaded for the period 1980-2022. However, because TSGT loads are located in more rural locations, historical temperatures were often unreliable or unavailable. Therefore, it was often necessary to use a nearby metropolitan area as a proxy for the temperatures for the TSGT loads.

Tri-ECO temperatures were based on the following locations and weightings:

- Denver – 55.4%
- Ft. Collins – 25.7%
- Colorado Springs – 7.85%
- Trinidad – 6.9%
- Pueblo – 3.9%
- Cheyenne – 0.3%

Tri-WCO temperatures were based on the following locations and weightings:

- Denver – 27.5%
- Ft. Collins – 14.5%
- Durango – 38.8%
- Grand Junction – 19.1%

Tri-NM temperatures were based on the following locations and weightings:

- Albuquerque – 41.1%
- Las Cruses – 43.9%
- Pueblo – 15%

Tri-WYWNE temperatures were based on the following locations and weightings:

- Cheyenne – 41.4%
- Casper – 58.6%

In addition to temperature, the neural net was provided with training variables that included day of week, hour of day, hour of week, 8-hour rolling average temperature, 24-hour rolling average temperature, and 48-hour rolling average temperature. “Networks” were created for Winter, Summer, and Shoulder periods. These trained networks were then applied to the NOAA weather data for the historical years 1980-2021 to develop synthetic load shapes for each of the 42 weather years.

Since the 42 years of historical weather data contains temperature data outside the range of that contained in the historical load set used to train the neural networks, those values were determined using peak load regressions developed outside the neural network. Peak load regressions were developed for summer afternoon, winter morning, and winter afternoon periods. These adjustment regressions were only applied to days in which the temperature fell outside the reasonable range of the 5-year historical data set. The figures below show the regressions performed for each of those three periods for each of the four TSGT load zones.

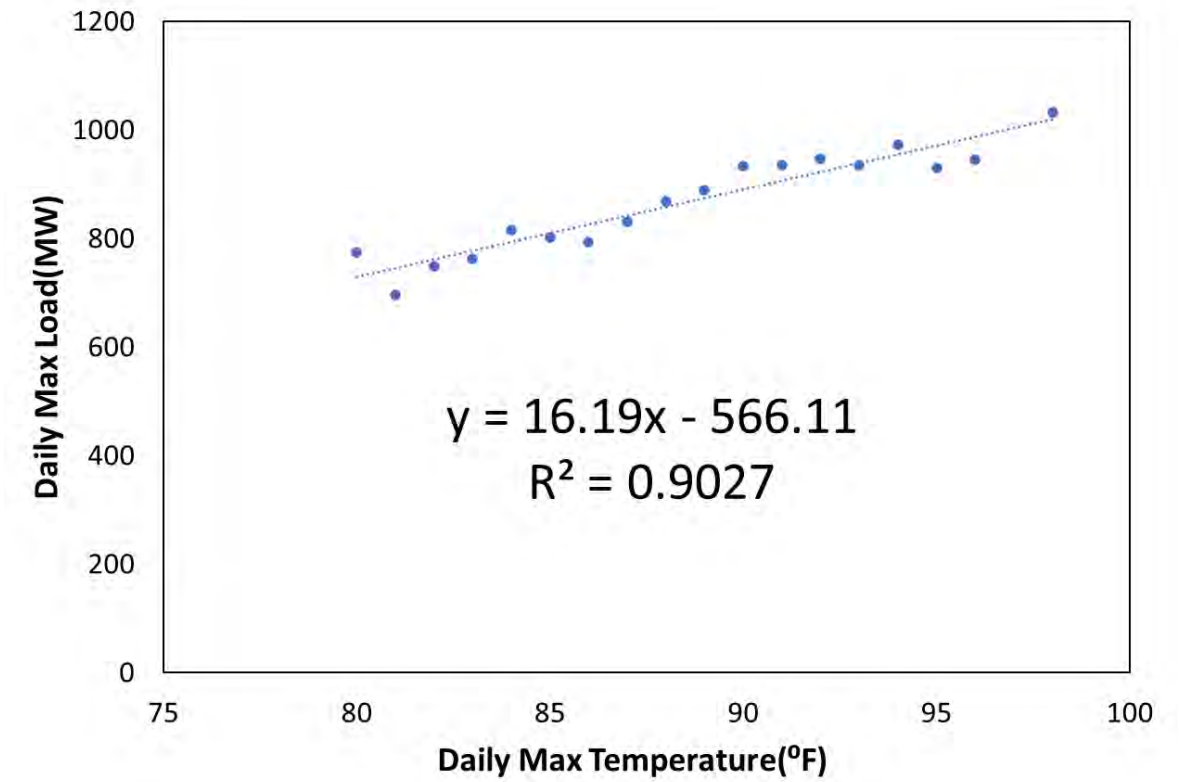


*Figure 12. Tri-ECO Summer Afternoon Extreme Temperature Regression*

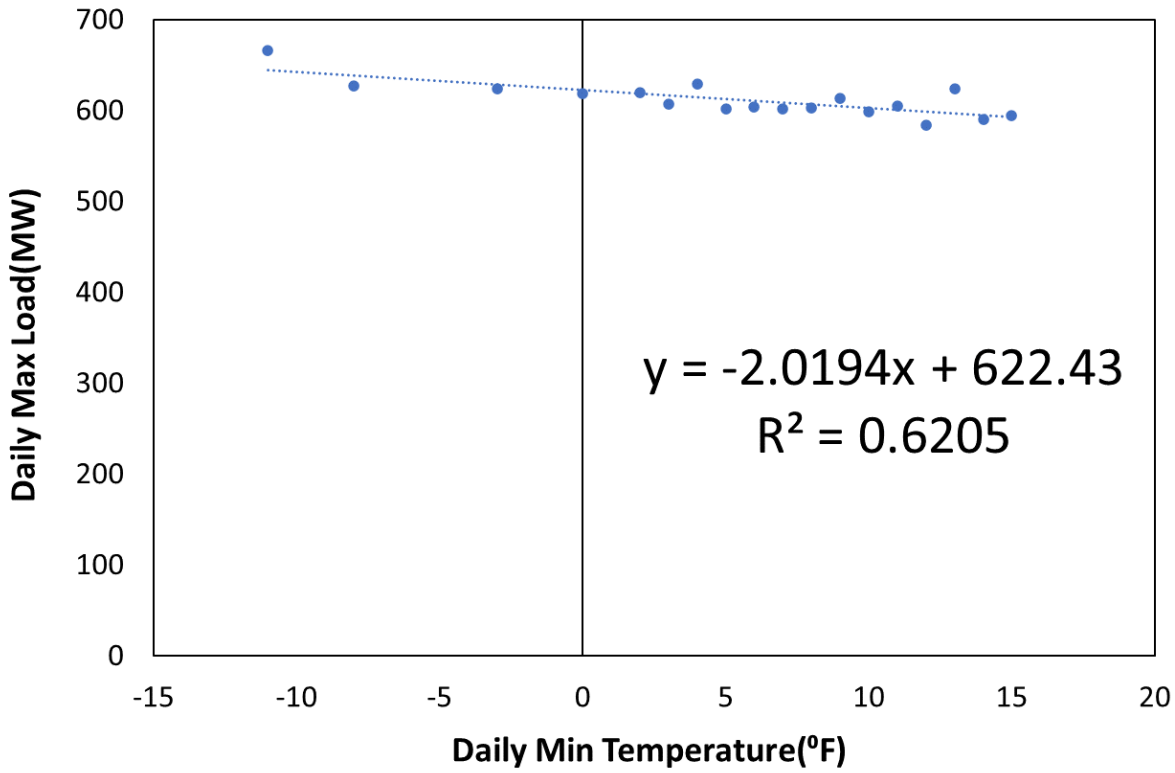


*Figure 13.Tri-ECO Winter Afternoon Extreme Temperature Regression*

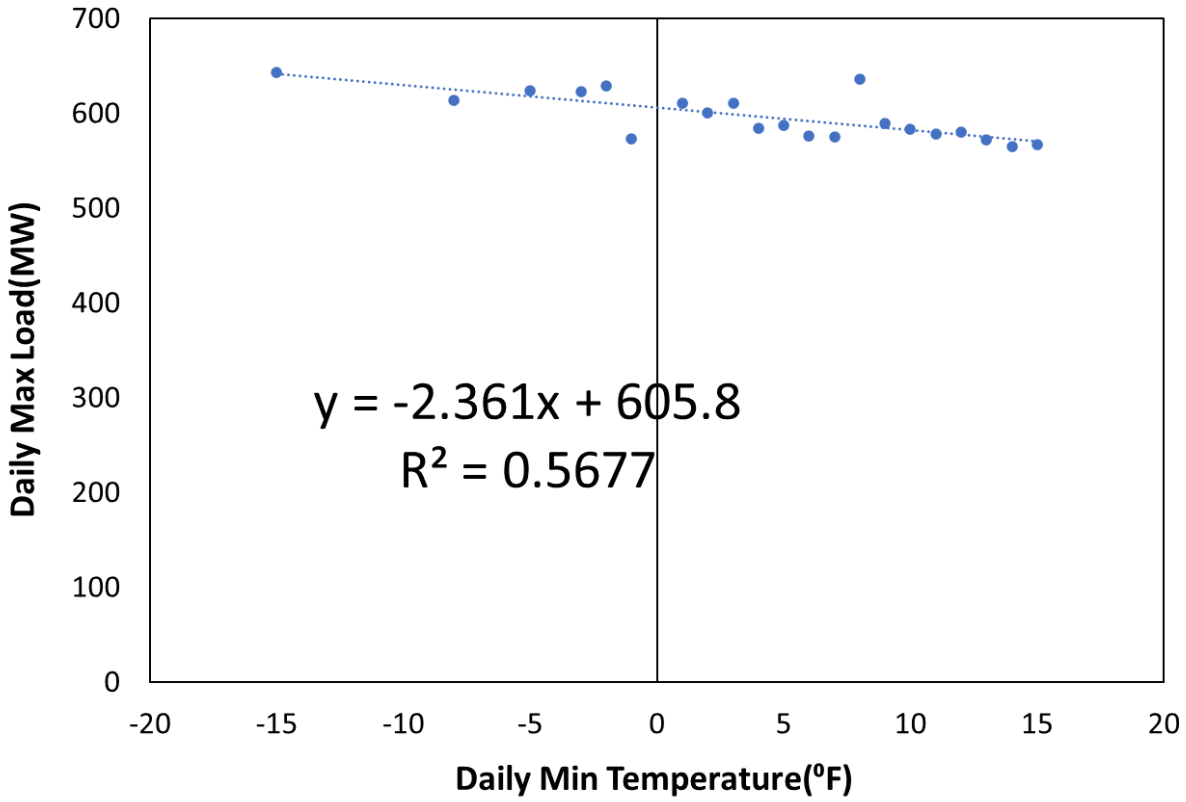


*Figure 14. Tri-ECO Winter Morning Extreme Temperature Regression*

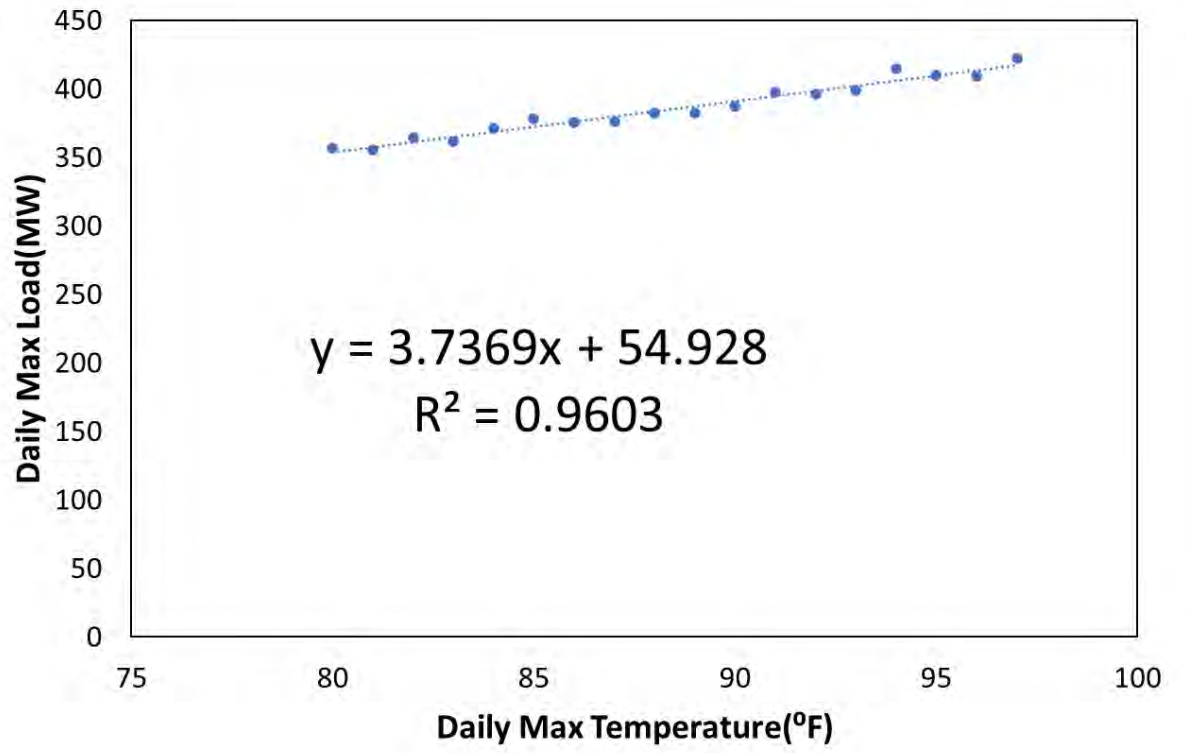


*Figure 15. Tri-WCO Summer Afternoon Extreme Temperature Regression*

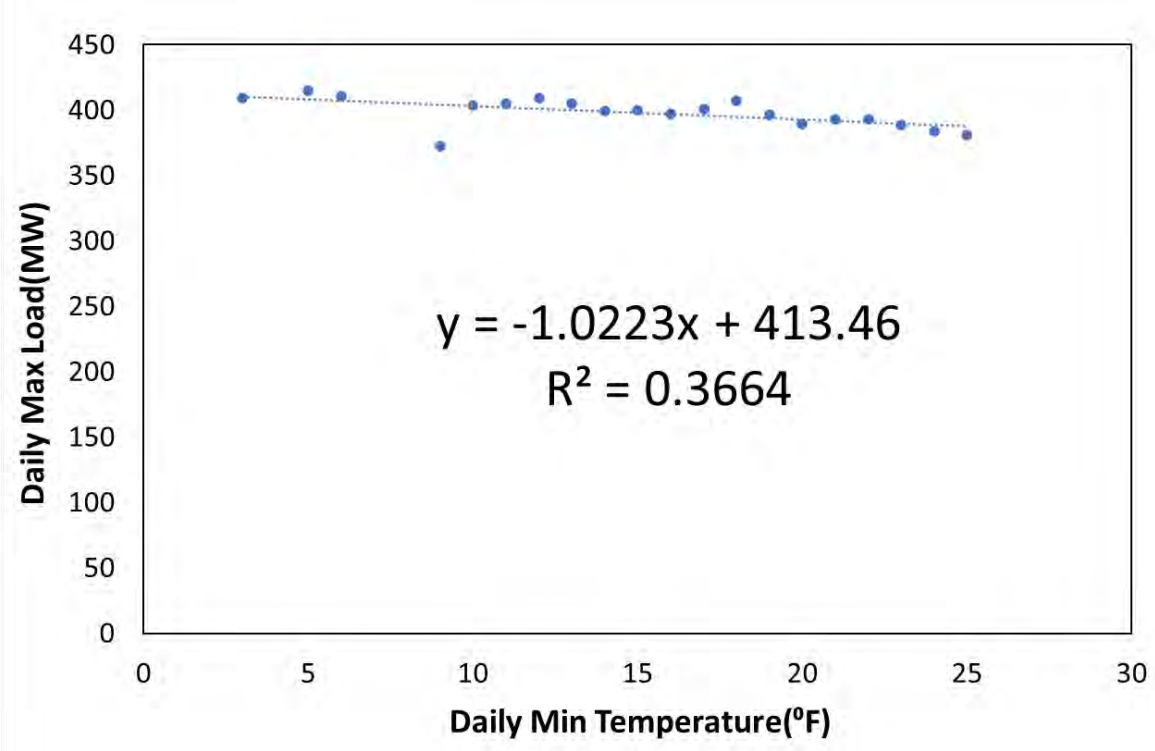


*Figure 16.Tri-WCO Winter Afternoon Extreme Temperature Regression*

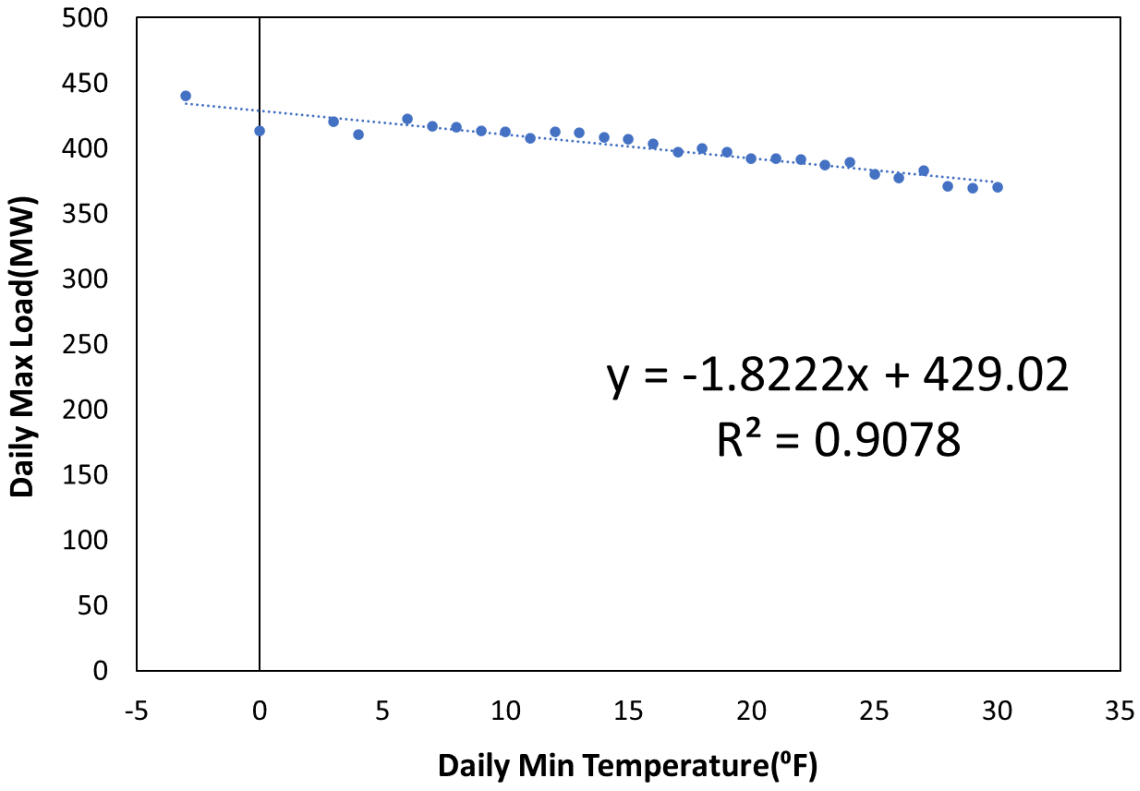


*Figure 17. Tri-WCO Winter Morning Extreme Temperature Regression*

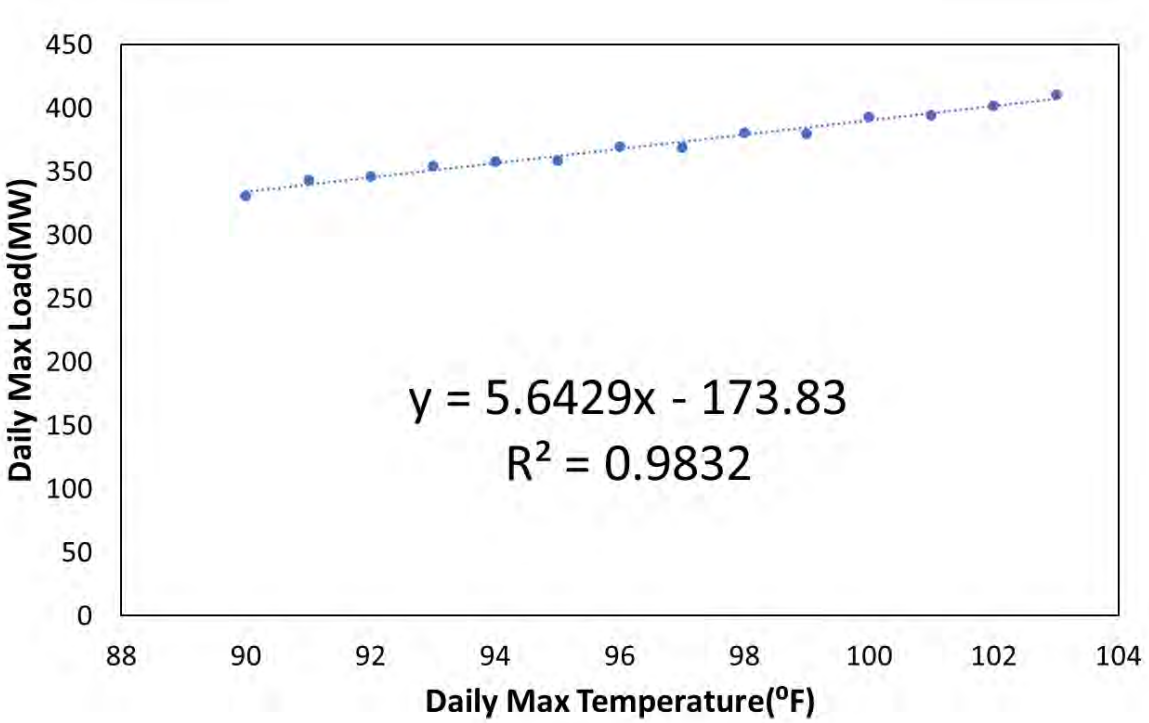


*Figure 18. Tri-NM Summer Afternoon Extreme Temperature Regression*

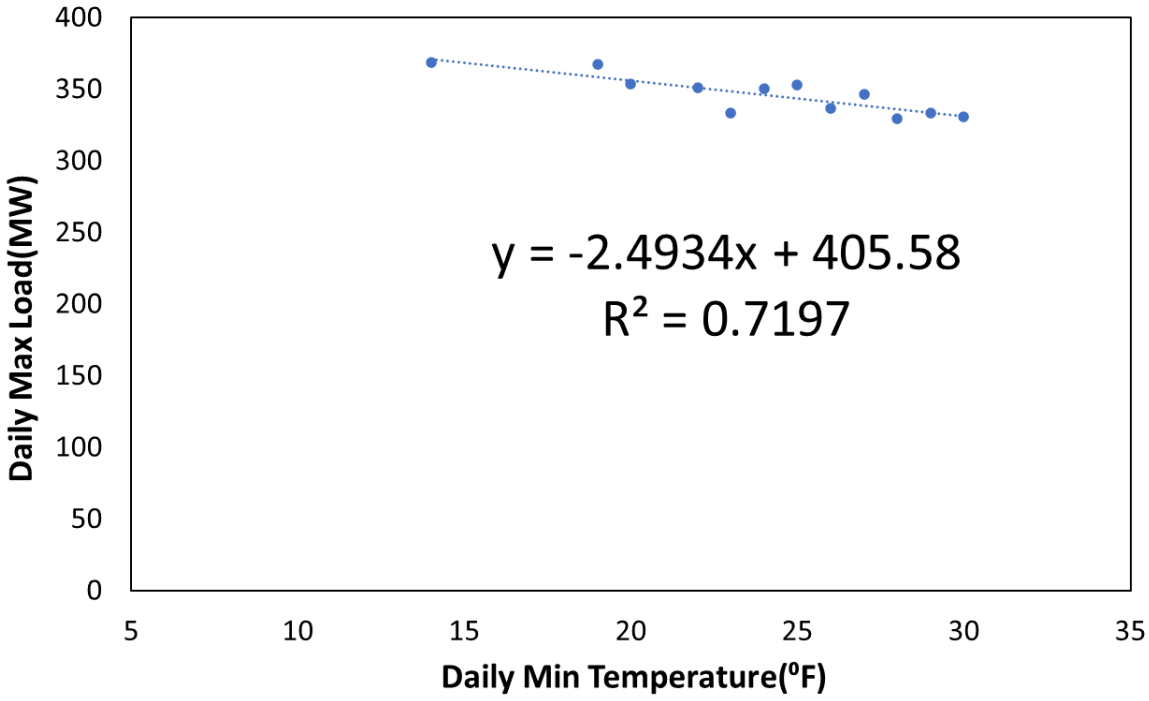


*Figure 19.Tri-NM Winter Afternoon Extreme Temperature Regression*

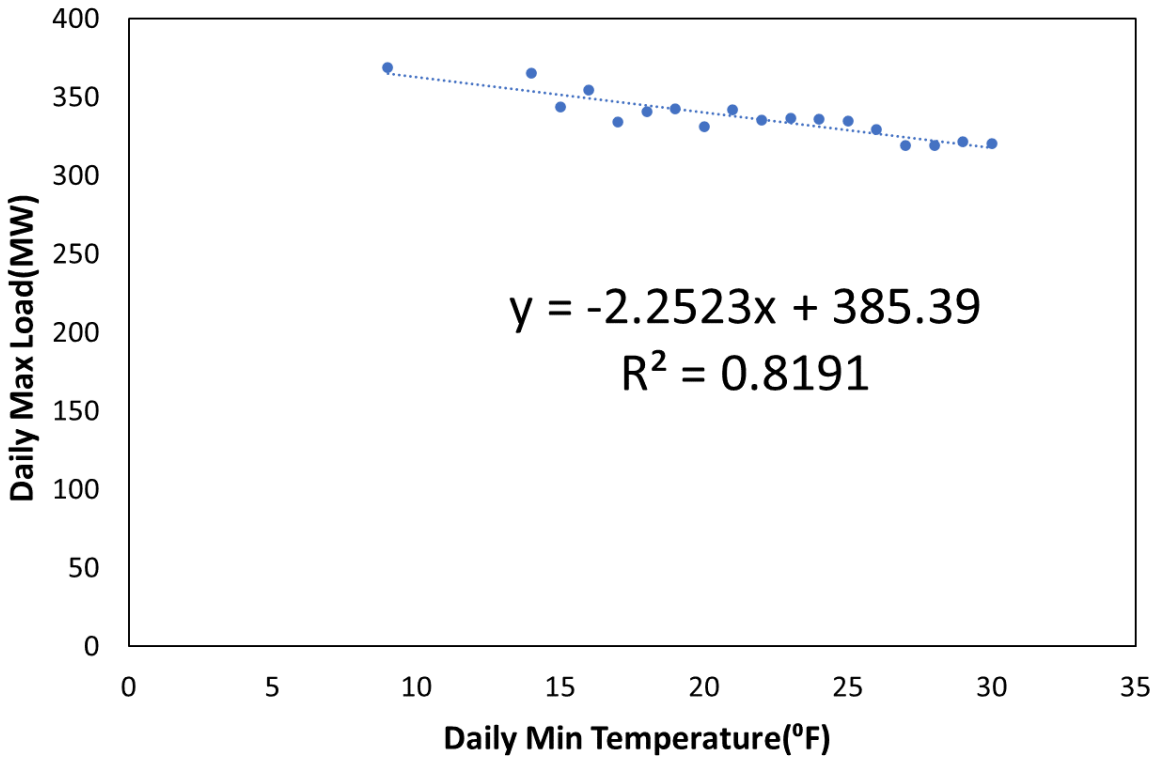


*Figure 20. Tri-NM Winter Morning Extreme Temperature Regression*

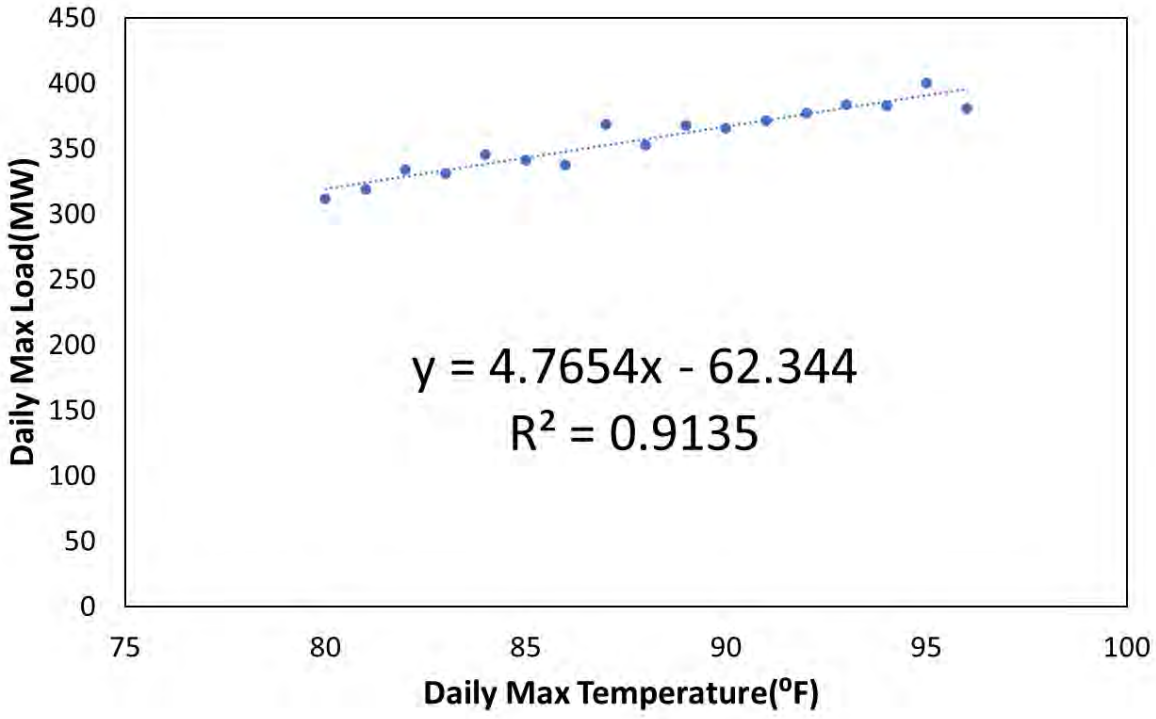


*Figure 21. Tri-WYWNE Summer Afternoon Extreme Temperature Regression*

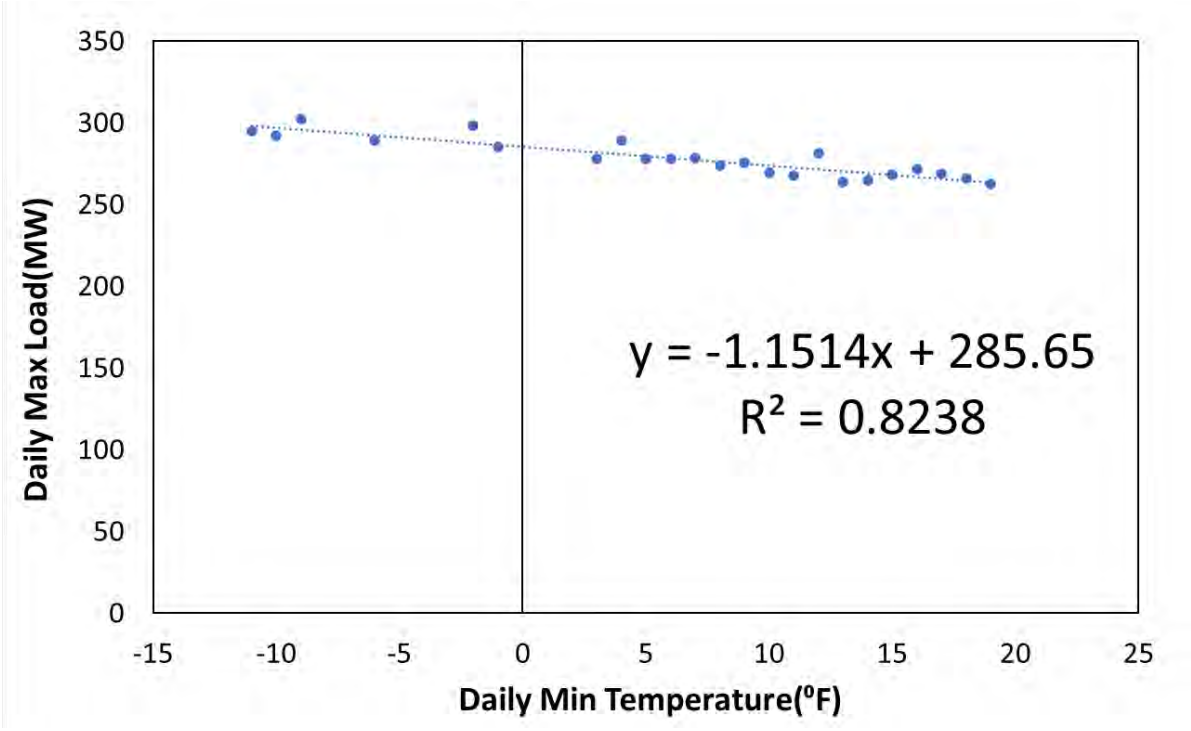


***Figure 22.Tri-WYWNE Winter Afternoon Extreme Temperature Regression***

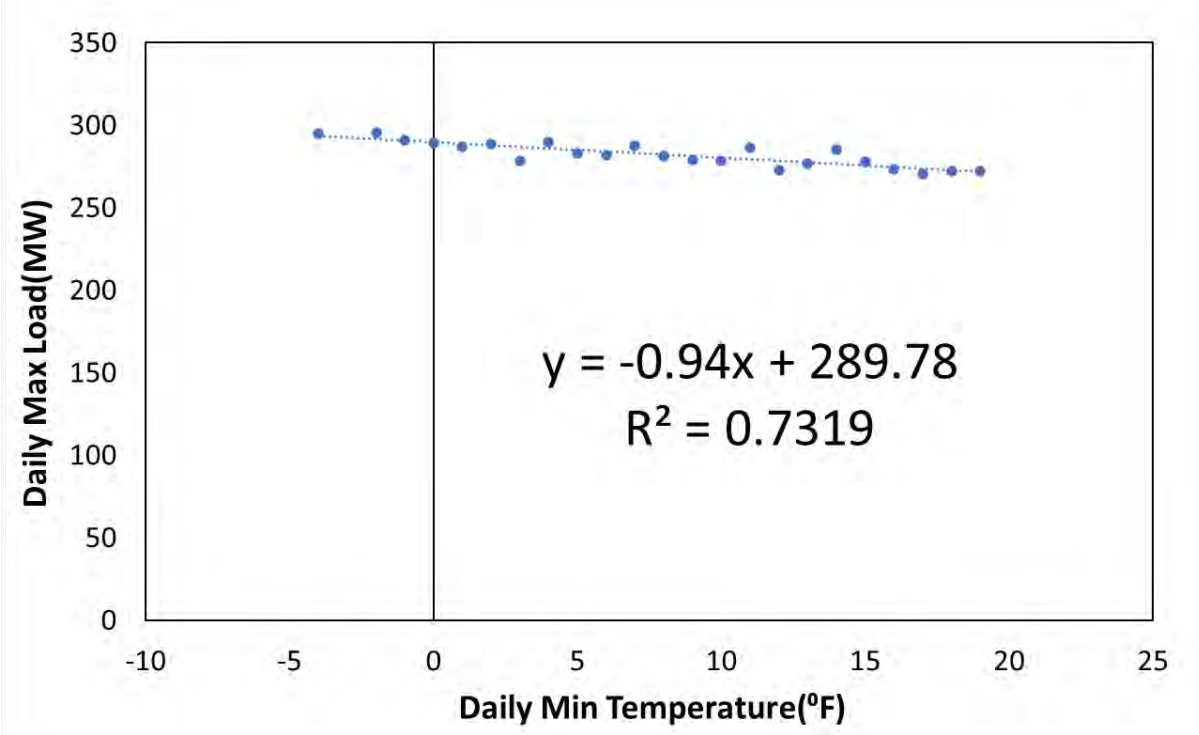


***Figure 23. Tri-WYWNE Winter Morning Extreme Temperature Regression***

The synthetic load shapes were then quality checked against the actual historical shapes to ensure their validity.

The figures below show a plot of the daily peak loads for each TSGT load region as a function of either the daily max or daily min temperature as appropriate. The figure compares the five years of historical data with the 42 years of synthetic data.

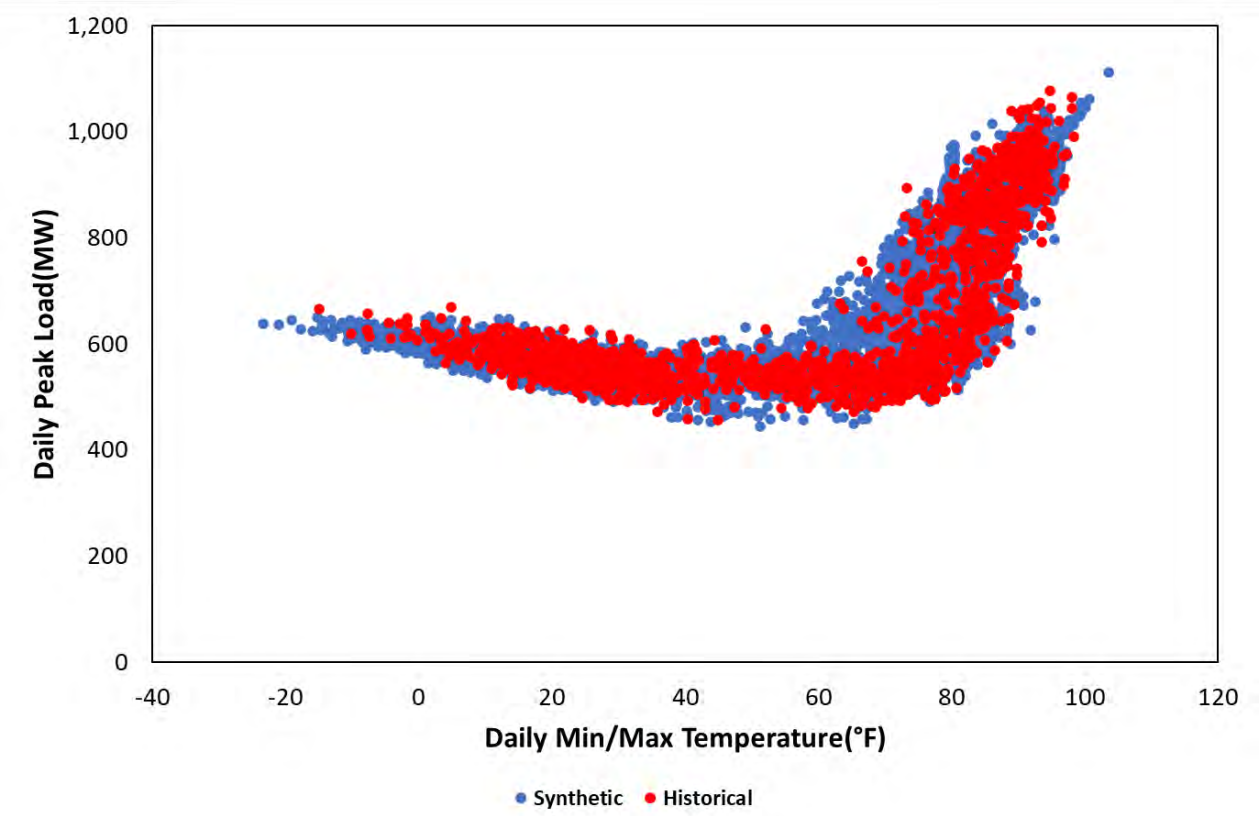


***Figure 24. Tri-ECO Synthetic vs. Historical Daily Peak Loads***

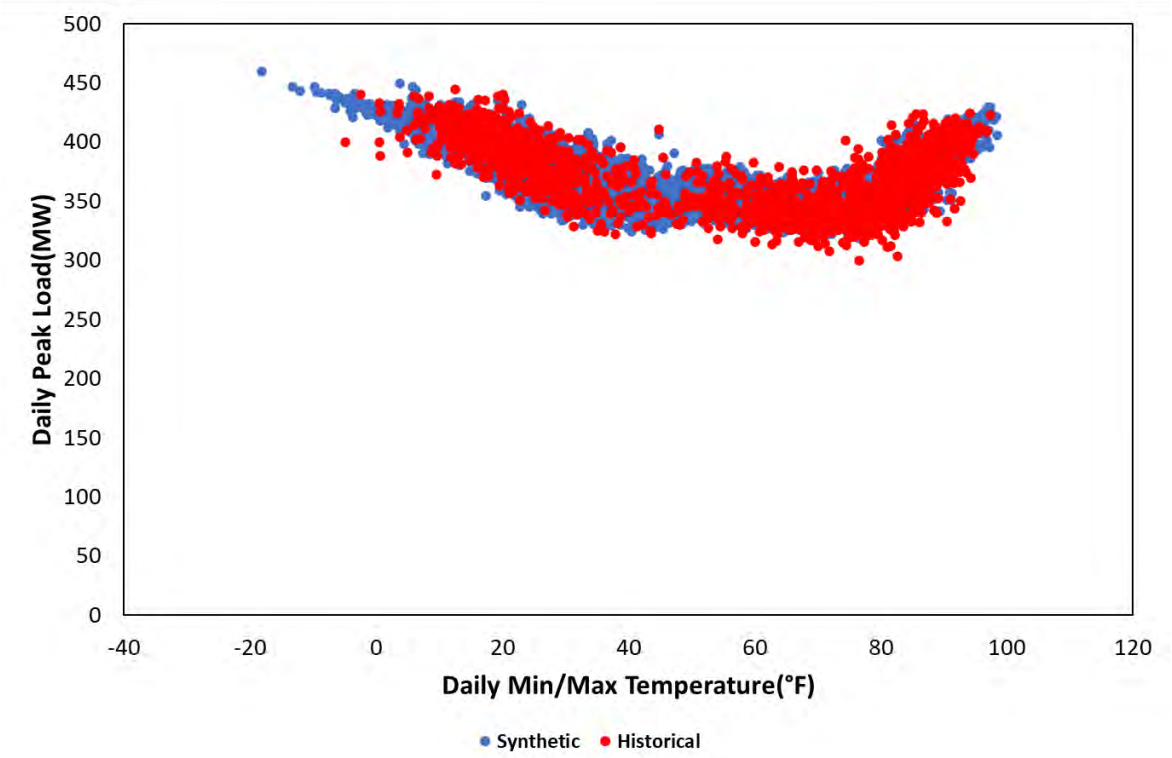


*Figure 25. Tri-WCO Synthetic vs. Historical Daily Peak Loads*

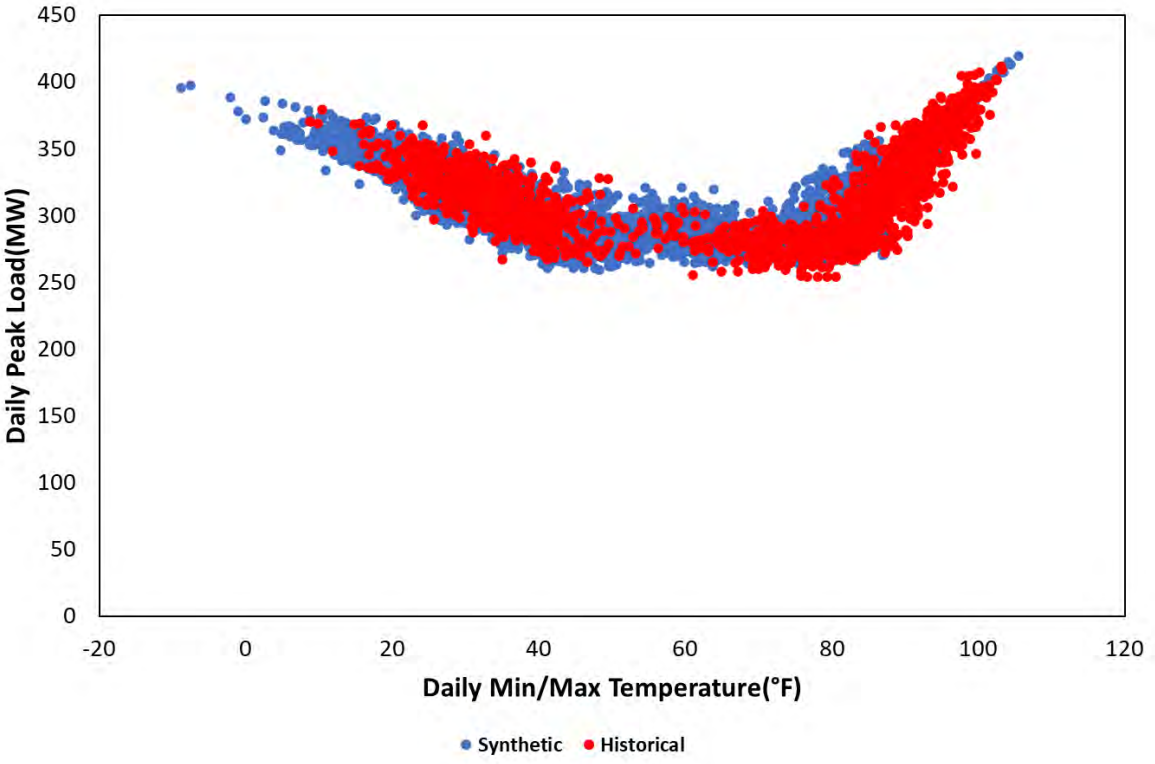


*Figure 26. Tri-NM Synthetic vs. Historical Daily Peak Loads*

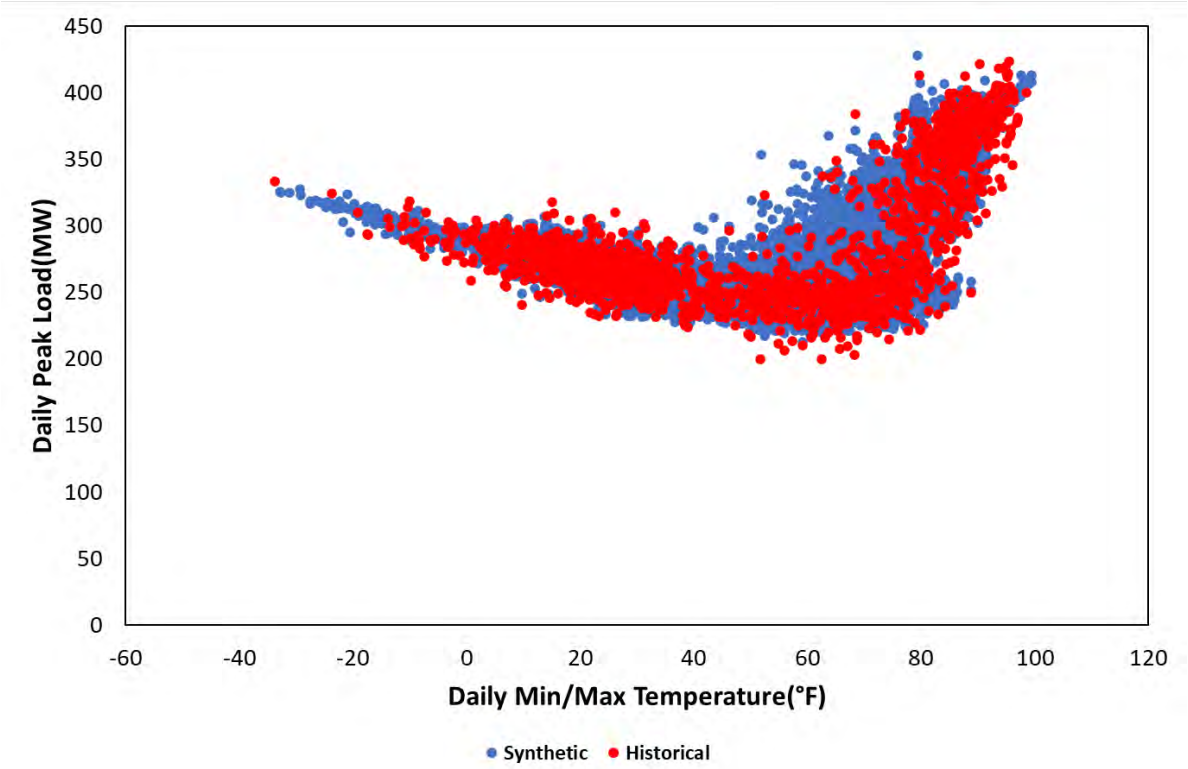


***Figure 27. Tri-WYWNE Synthetic vs. Historical Daily Peak Loads***

Focusing on the most extreme hours, the figures below show this same comparison for just those days in which temperatures were most extreme. The figure demonstrates a close correlation between the synthetic loads and the historical loads.

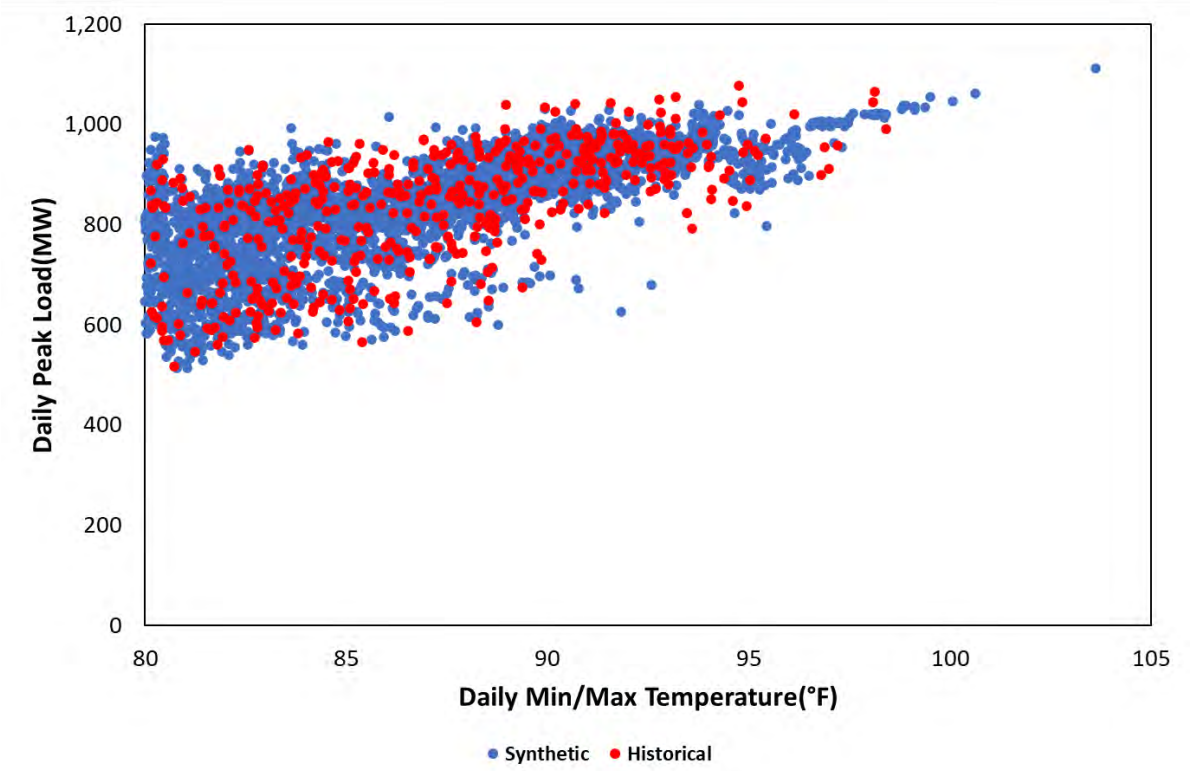


***Figure 28. Tri-ECO Synthetic vs. Historical Loads for Extreme Temperatures***

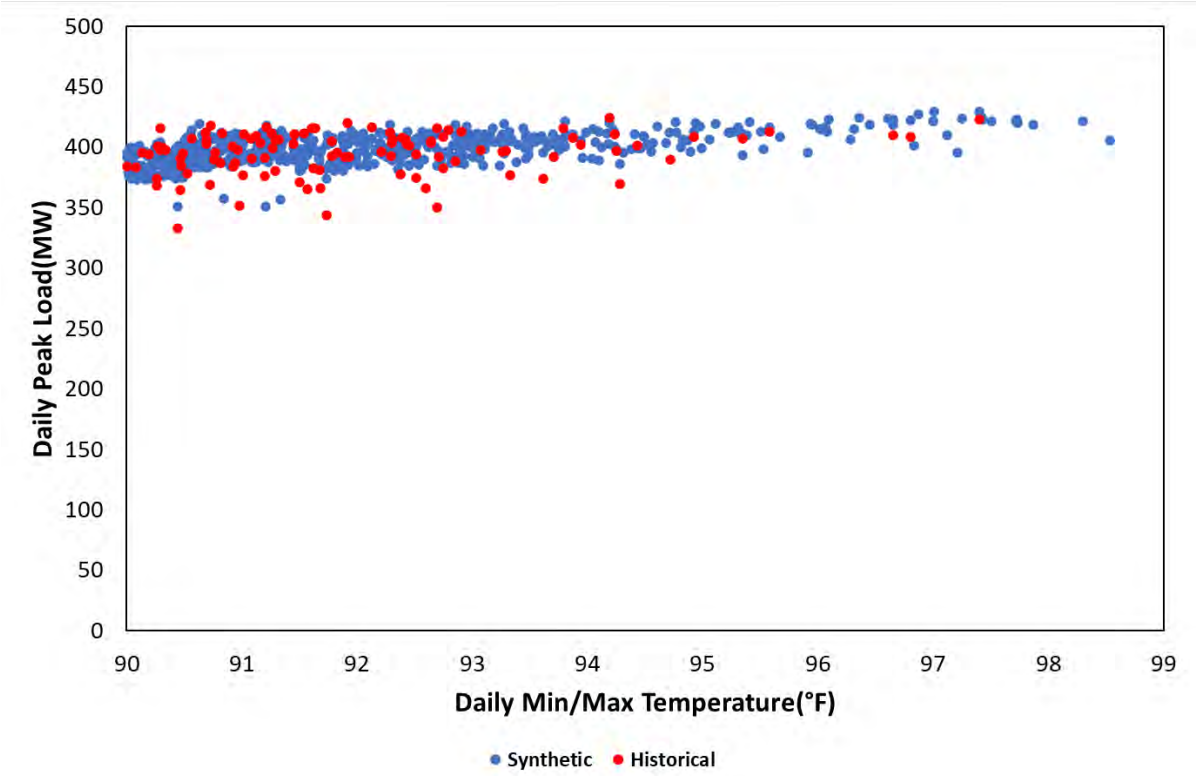


*Figure 29. Tri-WCO Synthetic vs. Historical Loads for Extreme Temperatures*

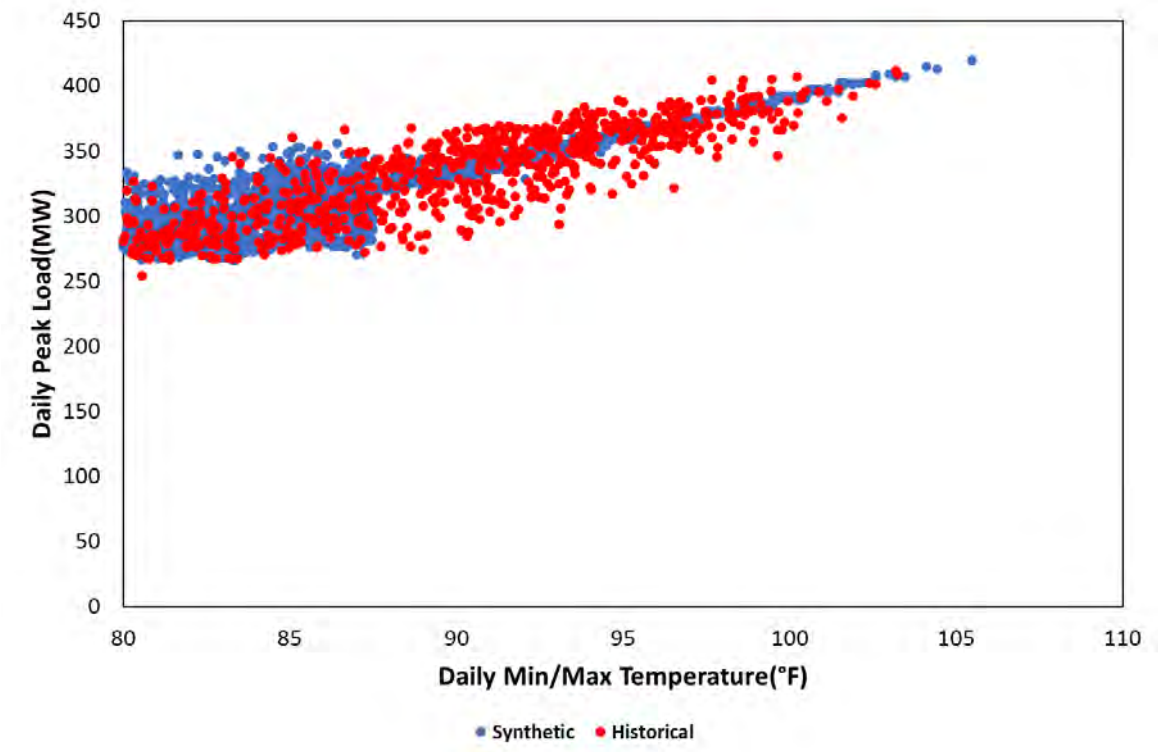


*Figure 30. Tri-NM Synthetic vs. Historical Loads for Extreme Temperatures*

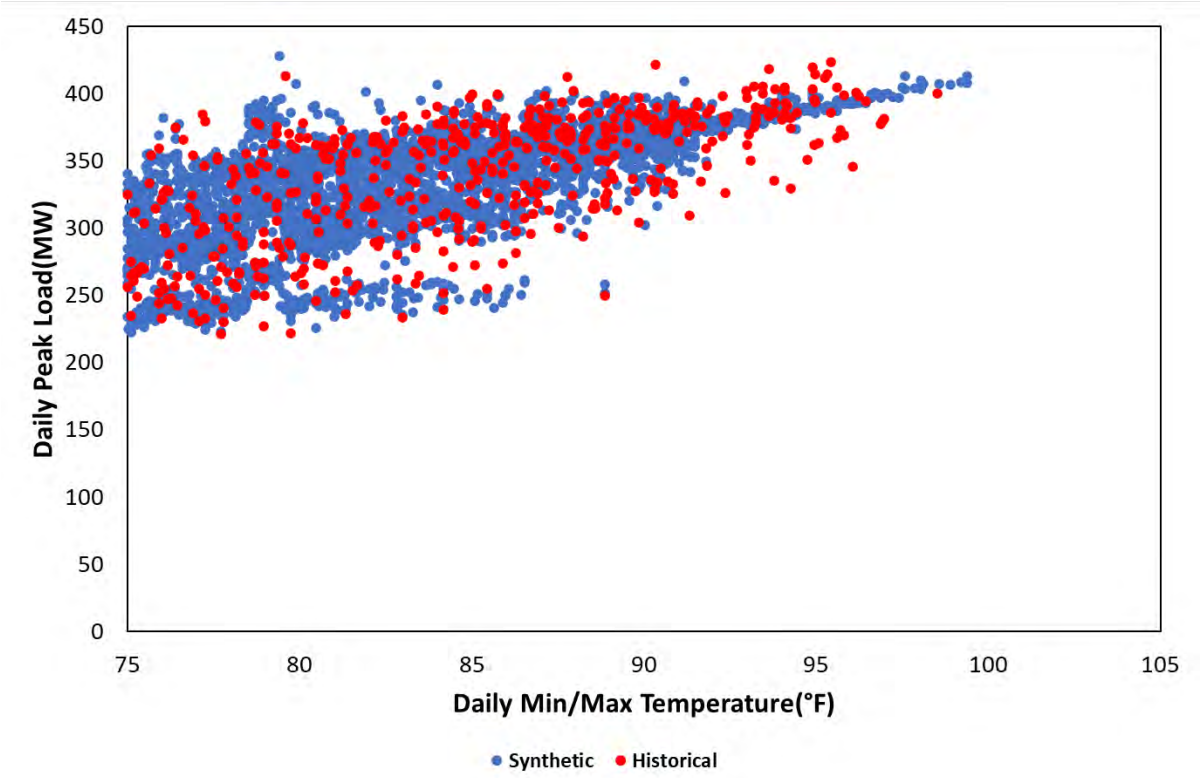


***Figure 31. Tri-WYWNE Synthetic vs. Historical Loads for Extreme Temperatures***

The development of the 42 synthetic load shapes results in a diverse set of annual peak loads. Within SERVM, these shapes were scaled such that the median of the last 10 years of annual peak loads will equal the TSGT weather normal forecasted peak load. The figures below show the summer and winter peak load variance resulting from the 42 synthetic load shapes for each of the TSGT load zones. The variance is shown on a percentage basis in terms of its divergence from the 10-year median (a.k.a., weather normal load), sorted from lowest to highest.

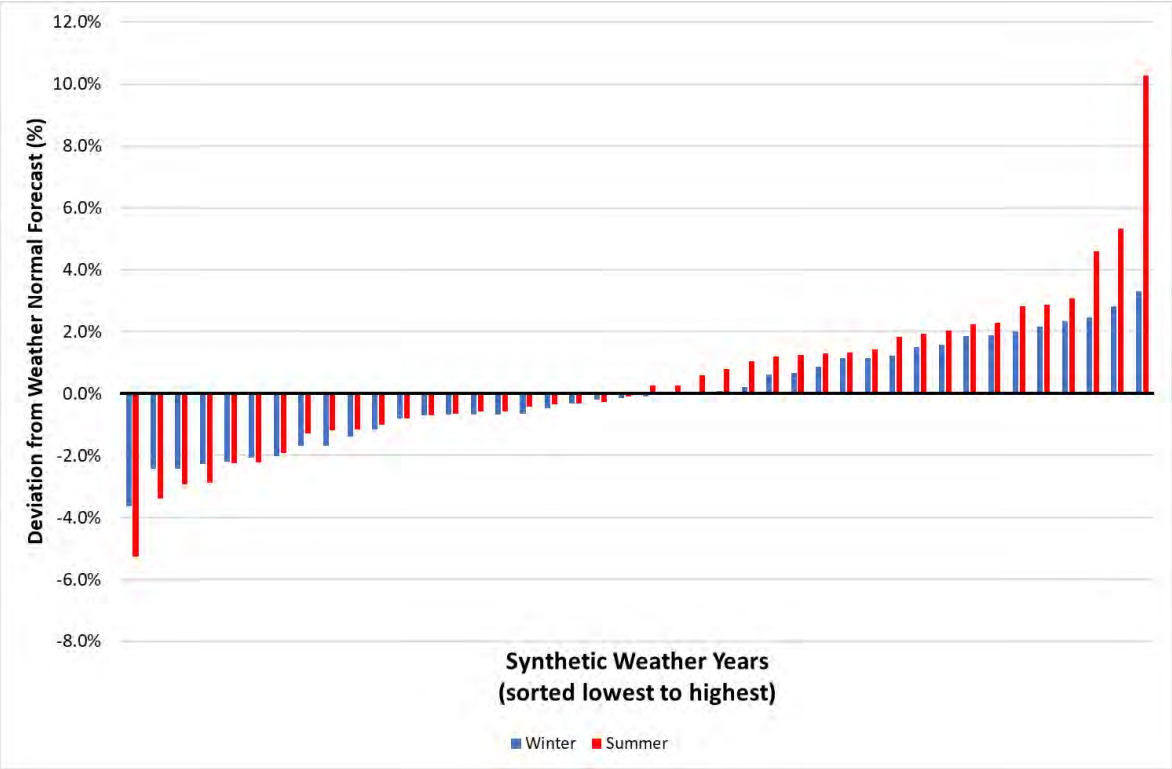


***Figure 32. Tri-ECO Peak Load Variance***

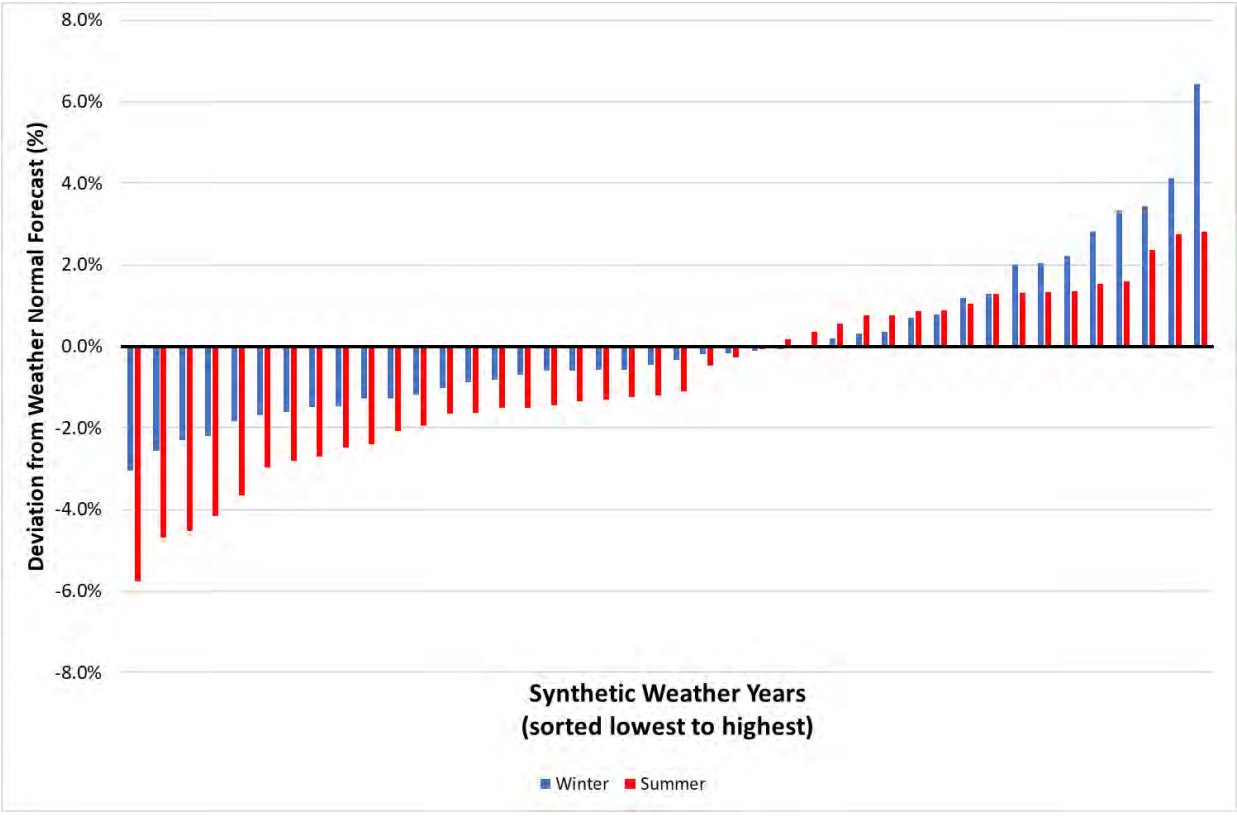


***Figure 33. Tri-WCO Peak Load Variance***

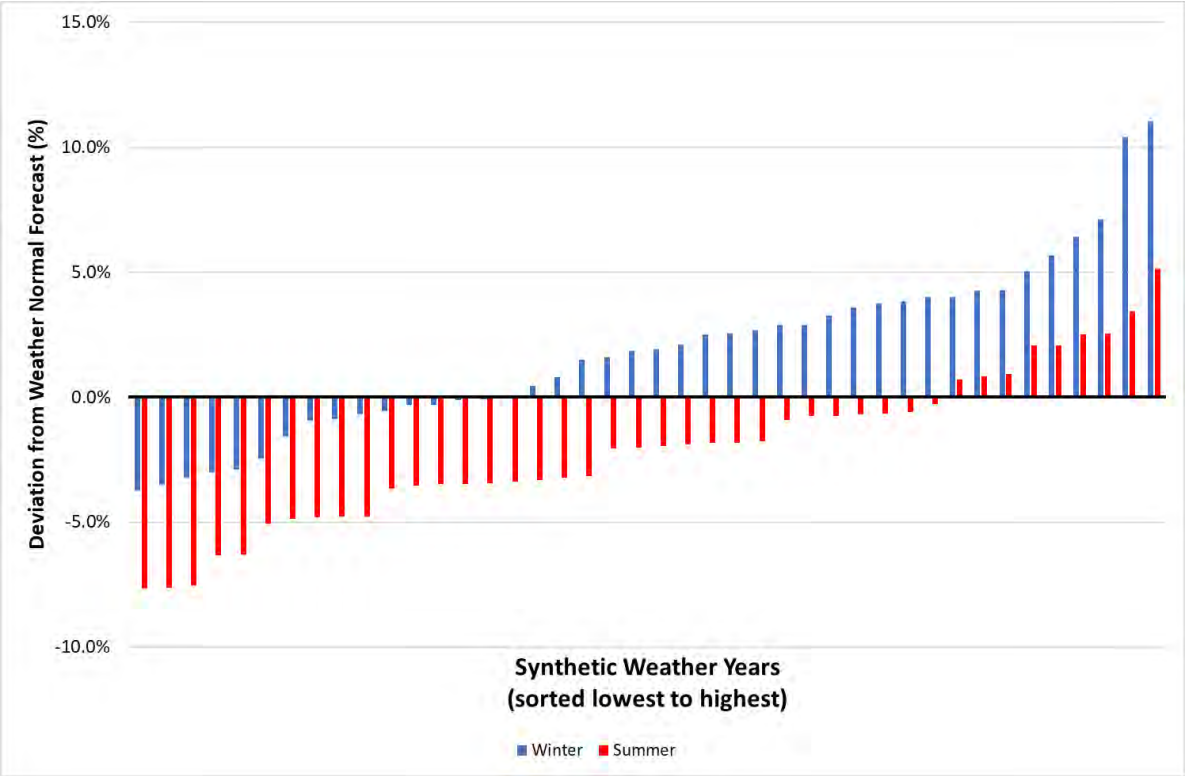


*Figure 34. Tri-NM Peak Load Variance*

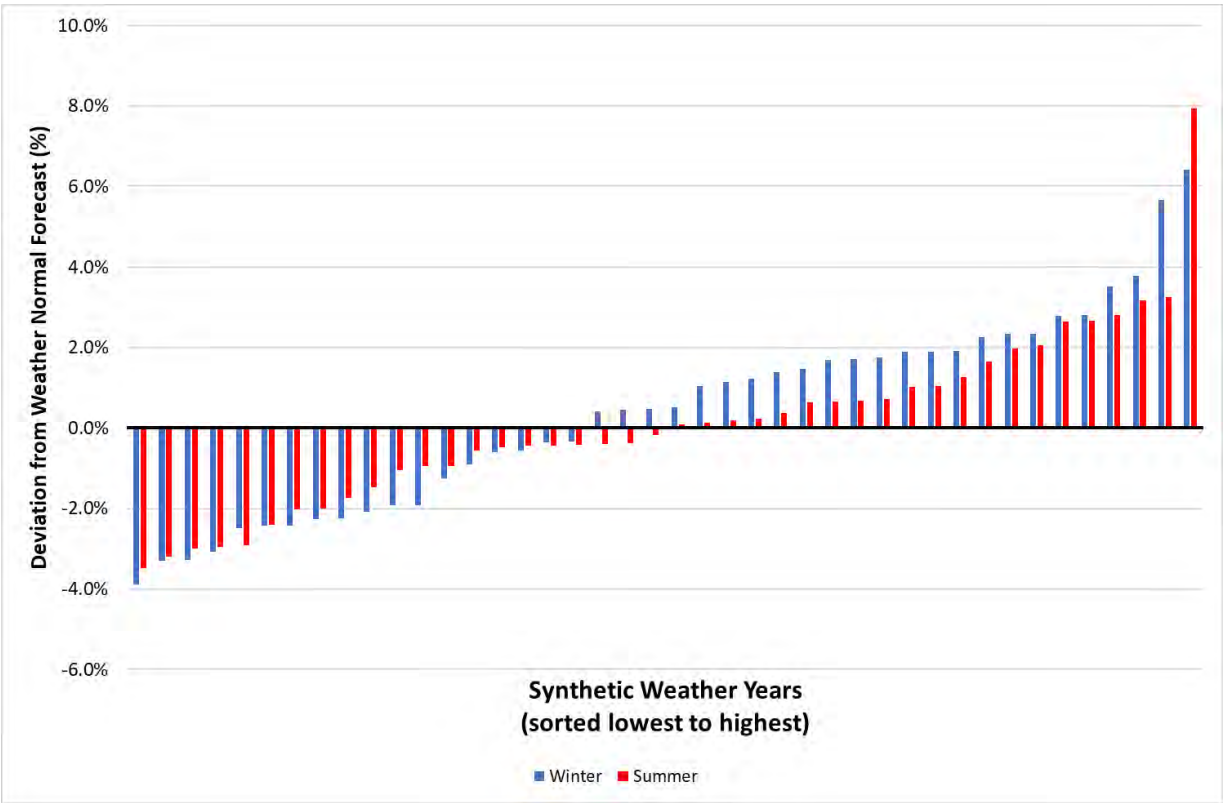


*Figure 35. Tri-WYWNE Peak Load Variance*

In addition to the raw loads, load modifiers were used to model incremental EE. The table below shows the 12x24 EE profile modeled for the EE programs in the Tri-ECO and Tri-WCO load zones. Values are shown in the percentage of maximum annual EE impact.

***Table 3. TSGT EE Shape***

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 53.8 | 48.3 | 45.7 | 30.8 | 39.9 | 40.1 | 38.7 | 41.2 | 40.0 | 35.3 | 28.0 | 31.3 |
| 2 | 52.3 | 44.9 | 43.7 | 29.6 | 38.8 | 39.2 | 37.8 | 39.2 | 38.0 | 33.5 | 25.2 | 29.0 |
| 3 | 51.3 | 44.2 | 42.3 | 30.2 | 39.6 | 39.5 | 38.2 | 38.9 | 38.7 | 32.9 | 24.4 | 27.9 |
| 4 | 52.1 | 44.1 | 43.3 | 32.7 | 41.6 | 40.4 | 40.8 | 39.7 | 41.5 | 33.6 | 25.9 | 29.9 |
| 5 | 53.8 | 47.2 | 47.3 | 36.2 | 44.8 | 42.8 | 43.6 | 42.3 | 45.0 | 38.2 | 29.2 | 33.0 |
| 6 | 57.2 | 51.0 | 51.9 | 40.2 | 49.9 | 47.5 | 48.1 | 45.5 | 47.6 | 42.8 | 33.4 | 37.3 |
| 7 | 61.6 | 55.1 | 55.3 | 43.9 | 53.6 | 52.1 | 53.3 | 49.0 | 51.3 | 47.3 | 37.8 | 42.2 |
| 8 | 64.8 | 58.3 | 59.5 | 46.5 | 57.9 | 58.2 | 59.8 | 52.6 | 53.8 | 51.3 | 42.5 | 46.4 |
| 9 | 67.7 | 62.5 | 63.4 | 49.0 | 59.2 | 63.2 | 66.5 | 55.3 | 58.1 | 54.0 | 45.7 | 50.2 |
| 10 | 69.4 | 66.3 | 65.1 | 50.5 | 62.3 | 67.4 | 70.7 | 60.0 | 64.4 | 56.1 | 47.5 | 51.9 |
| 11 | 70.3 | 67.1 | 68.1 | 50.8 | 63.9 | 72.4 | 74.2 | 61.0 | 68.2 | 58.8 | 48.1 | 53.0 |
| 12 | 70.4 | 67.4 | 68.5 | 52.3 | 64.8 | 75.9 | 75.0 | 60.9 | 71.6 | 60.8 | 49.0 | 53.6 |
| 13 | 70.2 | 67.4 | 69.2 | 53.1 | 68.6 | 78.1 | 75.7 | 61.1 | 76.0 | 61.3 | 49.4 | 54.0 |
| 14 | 70.9 | 67.3 | 69.9 | 54.0 | 70.1 | 79.0 | 77.6 | 63.8 | 77.5 | 63.3 | 50.2 | 53.5 |
| 15 | 70.9 | 67.0 | 70.6 | 54.8 | 72.2 | 80.5 | 80.4 | 66.7 | 78.4 | 64.5 | 50.7 | 54.2 |
| 16 | 71.9 | 68.1 | 71.1 | 55.3 | 73.4 | 80.5 | 81.3 | 70.5 | 80.5 | 65.7 | 51.7 | 55.6 |
| 17 | 73.3 | 69.6 | 72.6 | 57.4 | 73.9 | 81.5 | 81.5 | 72.4 | 79.3 | 66.4 | 52.8 | 56.6 |
| 18 | 76.8 | 71.1 | 74.1 | 58.2 | 72.4 | 80.0 | 81.4 | 72.7 | 76.2 | 65.4 | 54.5 | 58.0 |
| 19 | 78.0 | 72.4 | 75.7 | 57.0 | 68.5 | 77.0 | 77.6 | 69.2 | 72.6 | 64.1 | 55.1 | 58.7 |
| 20 | 77.8 | 72.9 | 74.6 | 54.7 | 63.6 | 69.7 | 72.7 | 65.8 | 67.1 | 61.5 | 53.6 | 57.4 |
| 21 | 74.7 | 70.8 | 71.1 | 49.9 | 58.5 | 63.1 | 65.6 | 60.1 | 60.2 | 56.1 | 50.1 | 53.9 |
| 22 | 69.6 | 66.7 | 65.6 | 44.5 | 51.4 | 55.3 | 57.3 | 53.4 | 52.5 | 49.9 | 44.9 | 48.3 |
| 23 | 64.1 | 59.8 | 58.6 | 38.1 | 45.9 | 48.0 | 48.3 | 47.5 | 46.1 | 43.7 | 38.5 | 41.8 |
| 24 | 58.2 | 52.4 | 50.6 | 33.2 | 39.6 | 41.8 | 42.4 | 41.7 | 40.9 | 38.8 | 32.8 | 35.7 |

The maximum annual EE impact for Tri-ECO in 2030 is 10.1 MW. The maximum annual EE impact for Tri-WCO in 2030 is 3.3 MW.

## ECONOMIC FORECAST ERROR

As described in the Study Framework subsection of the Introduction section of this document, five LFE multipliers with their associated probabilities were applied to each of the 42 historical load shapes. The LFE multipliers simulate the expected probability that the peak demand forecast would be missed because of errors in the forecast of economic growth. The multipliers were developed by looking at the historical error in the 4-year out forecast GDP assuming a peak demand sensitivity to changes in GDP of 0.4% per 1% change in GDP. The set of LFE multipliers along with their probability of occurrence used in this study are shown in the table below with a graphic representation in the figure that follows.

***Table 4. LFE Model***

| LFE | Probability |
|---|---|
| -4% | 7.9% |
| -2% | 24.0% |
| 0% | 36.2% |
| 2% | 24.0% |
| 4% | 7.9% |

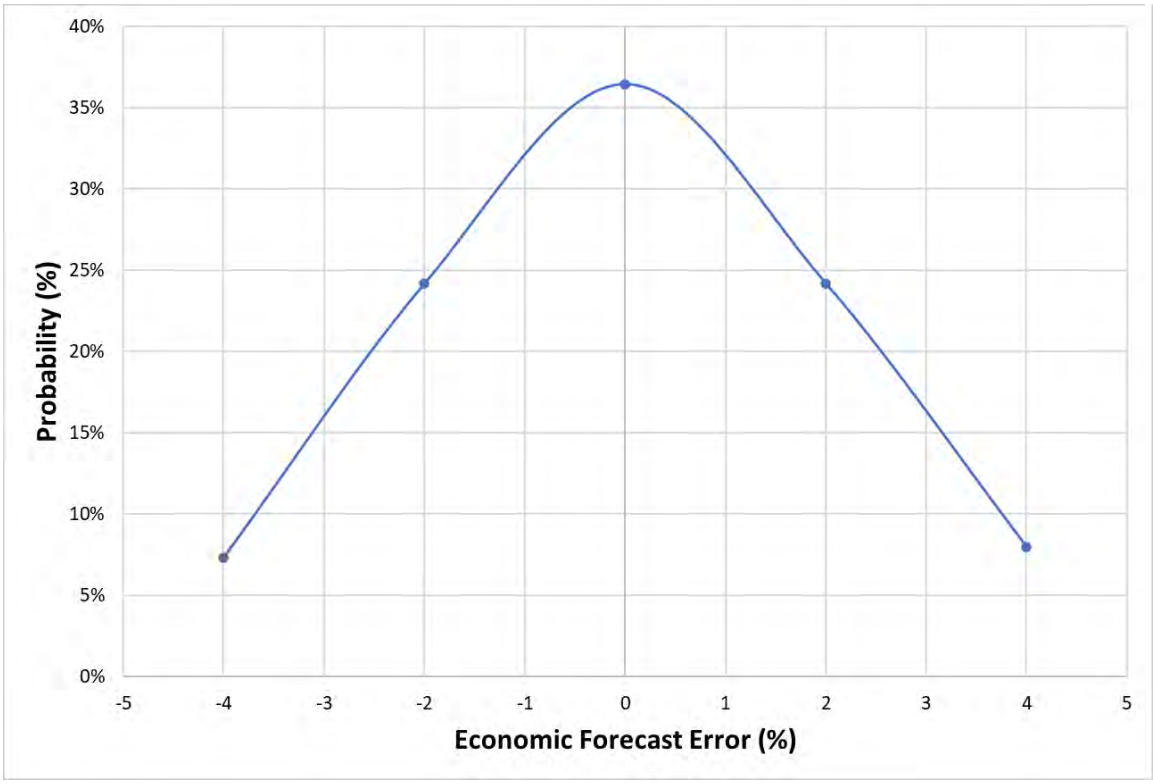


***Figure 36. LFE Model***

## CONVENTIONAL RESOURCE MODELING

Resources for neighboring entities were developed using publicly available information. Resources for TSGT were developed using data provided by TSGT as outlined in the subsections below.

### CONVENTIONAL GENERATING CAPACITY

The following table shows a summary of all the Conventional resources assumed to be available to TSGT in 2030, along with their corresponding summer capabilities. This list includes contract purchases and sales. Laramie River and Springerville are jointly owned coal units and the values shown represent the TSGT ownership share.

***Table 5. TSGT Conventional Resource Capacities***

| Unit Name | Unit Category | Load Region | Capacity MW |
|---|---|---|---|
| **Basin Ault** | Contract Purchase | TRI_ECO | 149.0 |
| **Basin Losses** | Contract Purchase | TRI_WYWNE | 8.0 |
| **Basin Stegal** | Contract Purchase | TRI_WYWNE | 119.0 |
| **Burlington 1** | CT | TRI_ECO | 48.0 |
| **Burlington 2** | CT | TRI_ECO | 48.0 |
| **Central Valley** | Contract Purchase | TRI_NM | 0.9 |

| | | | |
|---|---|---|---|
| **Knutson 1** | CT | TRI_ECO | 67.0 |
| **Knutson 2** | CT | TRI_ECO | 67.0 |
| **Laramie River 2** | Coal | TRI_WYWNE | 241.0 |
| **Laramie River 3** | Coal | TRI_WYWNE | 243.0 |
| **Limon 1** | CT | TRI_ECO | 67.0 |
| **Limon 2** | CT | TRI_ECO | 67.0 |
| **Native ECO** | Contract Purchase | TRI_ECO | 0.7 |
| **Native NM** | Contract Purchase | TRI_NM | 1.5 |
| **Native WCO** | Contract Purchase | TRI_WCO | 0.5 |
| **NWPP Purchase** | Contract Purchase | TRI_WCO | 0.9 |
| **NWPP Sale** | Contract Sale | TRI_WCO | -0.4 |
| **Pyramid_1** | CT | TRI_NM | 40.0 |
| **Pyramid_2** | CT | TRI_NM | 40.0 |
| **Pyramid_3** | CT | TRI_NM | 40.0 |
| **Pyramid_4** | CT | TRI_NM | 40.0 |
| **Shafer** | CC | TRI_ECO | 272.0 |
| **Small Power Producer** | Contract Purchase | TRI_WCO | 0.2 |
| **Springerville3** | Coal | TRI_NM | 319.0 |
| **SRSG Purchase** | Contract Purchase | TRI_NM | 0.1 |
| **SRSG Sale** | Contract Sale | TRI_NM | 0.0 |

With the exception of the three Basin contract purchases, which were modeled based on hourly profiles provided by TSGT, the contract purchases and sales were modeled as fixed injections that varied monthly.

## OUTAGE MODELING

Outage modeling consisted of two primary types of outages, planned maintenance outages (PO), and forced outages.

Planned Maintenance – SERVM can model Pos as either discrete schedules or an annual rate calculated as the percentage of hours in the year. If modeled as a PO rate, SERVM schedules planned maintenance in seasons where there would not typically be an expectation of reliability concerns. This determination is made by looking at all available weather year load shapes and developing a schedule that is least likely to cause reliability concerns. Maintenance rates were calculated using planned maintenance data provided by TSGT for the conventional resources.

Forced Outages – SERVM models forced outages using multiple sets of time to fail (TTF) and time to repair (TTR) inputs for both full and partial outages. Each resource has its own set of TTF and TTR inputs that are used to establish that resource's EFOR. Using Monte-Carlo techniques, a TTF value is chosen randomly for each generating resource. That resource is then allowed to operate until it reaches the TTF threshold, at which point it is forced offline. Once it is forced offline, a TTR value is chosen randomly to determine how long the resource will be unavailable. That resource remains

offline until it reaches the TTR threshold, at which point it is once again made available and a new TTF variable is chosen for the resource. With sufficient Monte-Carlo iterations, the EFOR of the resource converges to its expected value.

TSGT provided historical Generating Availability Data System (GADS) data that was used to create an initial set of TTR and TTF values for each of the conventional resources. These TTR and TTF values were then tuned to targeted EFOR values provided by TSGT. The table below shows both the EFOR and the planned maintenance rates used for each conventional resource. All values are shown in percentages.

***Table 6. Resource Outage Rates***

| Unit Name | EFOR | PO Rate |
|---|---|---|
| **Burlington 1** | 30.0 | 0.8 |
| **Burlington 2** | 30.0 | 0.8 |
| **Knutson 1** | 7.3 | 5.3 |
| **Knutson 2** | 7.3 | 5.3 |
| **Laramie River 2** | 9.3 | 8.4 |
| **Laramie River 3** | 9.3 | 8.4 |
| **Limon 1** | 6.4 | 1.5 |
| **Limon 2** | 6.4 | 1.5 |
| **Pyramid_1** | 8.1 | 7.5 |
| **Pyramid_2** | 8.1 | 7.5 |
| **Pyramid_3** | 8.1 | 7.5 |
| **Pyramid_4** | 8.1 | 7.5 |
| **Shafer** | 7.6 | 3.6 |
| **Springerville 3** | 9.2 | 6.6 |

## HEAT RATES

While heat rates do not have a direct impact on the reliability of the system, it is important to accurately represent the relative dispatch of resources on the system so that outages (which are affected by hours of operation and thus do affect reliability) can be accurately modeled. Heat input requirements are modeled within SERVM using binomial (a.k.a., A-B-C) heat rate coefficients. Total heat input, average heat rates, and incremental heat rates, therefore, would be determined using the following formulas:

Total Heat Input = $A + B*X + C*X^2$
Average Heat Rate = $A/X + B + C*X$ and
Incremental Heat Rate = $B + 2*C*X$

Where X = the output of the resource in MW.

Heat rate coefficients for the conventional resources were provided by TSGT. The resulting average heat rate at maximum capacity is shown in the table below.

***Table 7. TSGT Unit Heat Rates***

| Unit Name | Unit Category | Heat Rate (MMBtu/kWh) |
|---|---|---|
| **Burlington 1** | CT | 14.0 |
| **Burlington 2** | CT | 14.0 |
| **Knutson 1** | CT | 11.6 |
| **Knutson 2** | CT | 11.6 |
| **Limon 1** | CT | 11.9 |
| **Limon 2** | CT | 11.9 |
| **Pyramid_1** | CT | 9.7 |
| **Pyramid_2** | CT | 9.7 |
| **Pyramid_3** | CT | 9.7 |
| **Pyramid_4** | CT | 9.7 |
| **Shafer** | CC | 9.3 |
| **Laramie River 2** | Coal | 10.0 |
| **Laramie River 3** | Coal | 10.4 |
| **Springerville 3** | Coal | 10.0 |

## FUEL COSTS

As with heat rates, precise accuracy in fuel costs does not directly impact reliability. However, as with heat rates, the relative cost of one fuel source to another can affect unit operations, which in turn can affect unit outage modeling. Monthly fuel costs were provided by TSGT as shown in the figure below for the 2030 study year in 2030 dollars. Fuel prices for other regions and technologies were determined from publicly available sources.



***Figure 37. TSGT Monthly Fuel Costs***

## OTHER CONVENTIONAL DATA

Other conventional resources data provided by TSGT included startup profiles, variable operation and maintenance, minimum capacities, minimum uptime, minimum downtime, and ramp rates. These were modeled as part of the analysis but had no direct bearing on the determination of the reserve margin except to the extent they may have affected hours of operation and thus (ultimately) outage profiles.

## CUSTOMER RESOURCE MODELING

The following table shows the distributed generation and partial requirements resources provided by the TSGT retail service provider customers. Except for the solar and wind resources, these were all modeled as fixed injections. The BTMPV represents customer rooftop solar, and values were estimated and assumed based on information provided by TSGT.

***Table 8. Customer Provided Resources***

| Unit Name | Unit Category | Region | Capacity MW |
|---|---|---|---|
| **BTMPV_ECO** | BTMPV | TRI_ECO | 89.4 |
| **BTMPV_NM** | BTMPV | TRI_NM | 36.9 |
| **BTMPV_WCO** | BTMPV | TRI_WCO | 40.9 |
| **BTMPV_WYWNE** | BTMPV | TRI_WYWNE | 35.8 |
| **DG_ECO** | Distributed Gen | TRI_ECO | 9.6 |
| **DG_Solar_ECO** | Distributed Solar | TRI_ECO | 185.6 |
| **DG_Solar_NM** | Distributed Solar | TRI_NM | 21.3 |

| | | | |
|---|---|---|---|
| **DG_Solar_WCO** | Distributed Solar | TRI_WCO | 24.7 |
| **DG_Solar_WYWNE** | Distributed Solar | TRI_WYWNE | 0.5 |
| **DG_WCO** | Distributed Gen | TRI_WCO | 10.3 |
| **DG_Wind_ECO** | Distributed Wind | TRI_ECO | 8.0 |
| **PR_NM** | Distributed Gen | TRI_NM | 30.0 |
| **PR_WCO** | Distributed Gen | TRI_WCO | 86.0 |
| **PR_WYWNE** | Distributed Gen | TRI_WYWNE | 47.0 |

See renewables sections below for details on how the solar and wind profiles were calculated.

## SOLAR RESOURCE MODELING

In addition to the BTMPV and distributed solar brought by its retail service providers, TSGT has nine existing and/or planned solar facilities. The following table shows the list of modeled solar resources, with their locations mapped in the figure that follows the table.

***Table 9. TSGT Solar Facilities***

| Unit Name | Capacity |
|---|---|
| **Alta Luna** | 25 |
| **Axial** | 145 |
| **Cimarron** | 30 |
| **Coyote Gulch** | 140 |
| **Dolores Canyon** | 110 |
| **Escalante** | 200 |
| **San Isabel** | 30 |
| **Spanish Peaks 1** | 100 |
| **Spanish Peaks 2** | 40 |

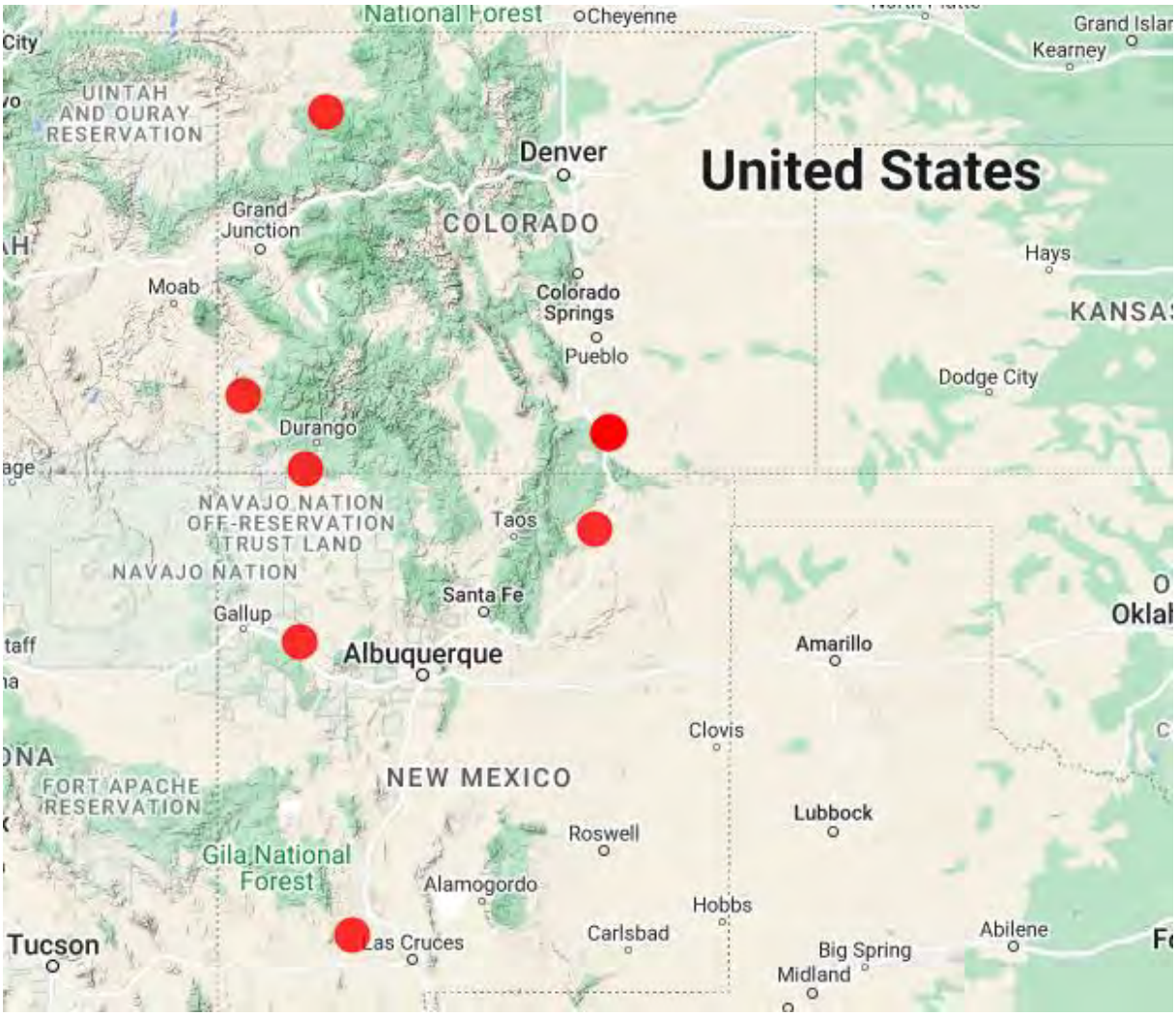


***Figure 38. Location of TSGT Solar Resources***

GPS coordinates for these locations can be found in the Appendix. Three of the resources, Spanish Peak 1 and 2 and San Isabel, are essentially co-located and were modeled as a single location.

SERVM models renewable resources as an hourly profile for each weather year.

To create the weather year profiles, irradiance data for these seven locations were downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer for the years 1998 to 2020.[3] The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar plants.[4] Solar profiles for 1980 to 1997 and 2021 were selected by using the daily solar profiles from the day that most closely matched the peak load for the APS load out of all the days +/- 2 days of the source day for the 1998 to 2020 interval. The profiles for the remaining years 1998 to 2020 came directly from the solar shape output data from SAM.

[3] https://maps.nrel.gov/nsrdb-viewer/
[4] https://sam.nrel.gov/

For the BTMPV and Distributed solar facilities brought by the retail service providers, an aggregate profile was created by combining the profiles of all seven locations.

To ensure appropriate capacity and energy contributions, the resulting profiles were then adjusted using the inverter loading ratio (ILR) to achieve the desired capacity factor. The table below shows the list of solar sites with their historical capacity factor and the modeled ILR that achieves that capacity factor. For units with no historical data, the ILR and final capacity factor are assumed as shown to achieve an assumed 30% capacity factor.

***Table 10. Solar Facility ILR and Historical Capacity Factors***

| Unit Name | Historical CF | ILR |
|---|---|---|
| **Alta Luna** | 31.7% | 1.075 |
| **Axial** | | 1.24 |
| **Cimarron** | 23.5% | 1.06 |
| **Coyote Gulch** | | 1.07 |
| **Dolores Canyon** | | 1.11 |
| **Escalante** | | 1.03 |
| **San Isabel** | 28.6% | 1.04 |
| **Spanish Peaks 1** | | 1.1 |
| **Spanish Peaks 2** | | 1.1 |

The figures below show respectively the resulting summer daily output profiles (average of June through September) for tracking, and fixed technologies for each of the seven sites modeled. The profiles assume an ILR of 1.0.[5]

[5] i.e., the average of all July days including all weather years.

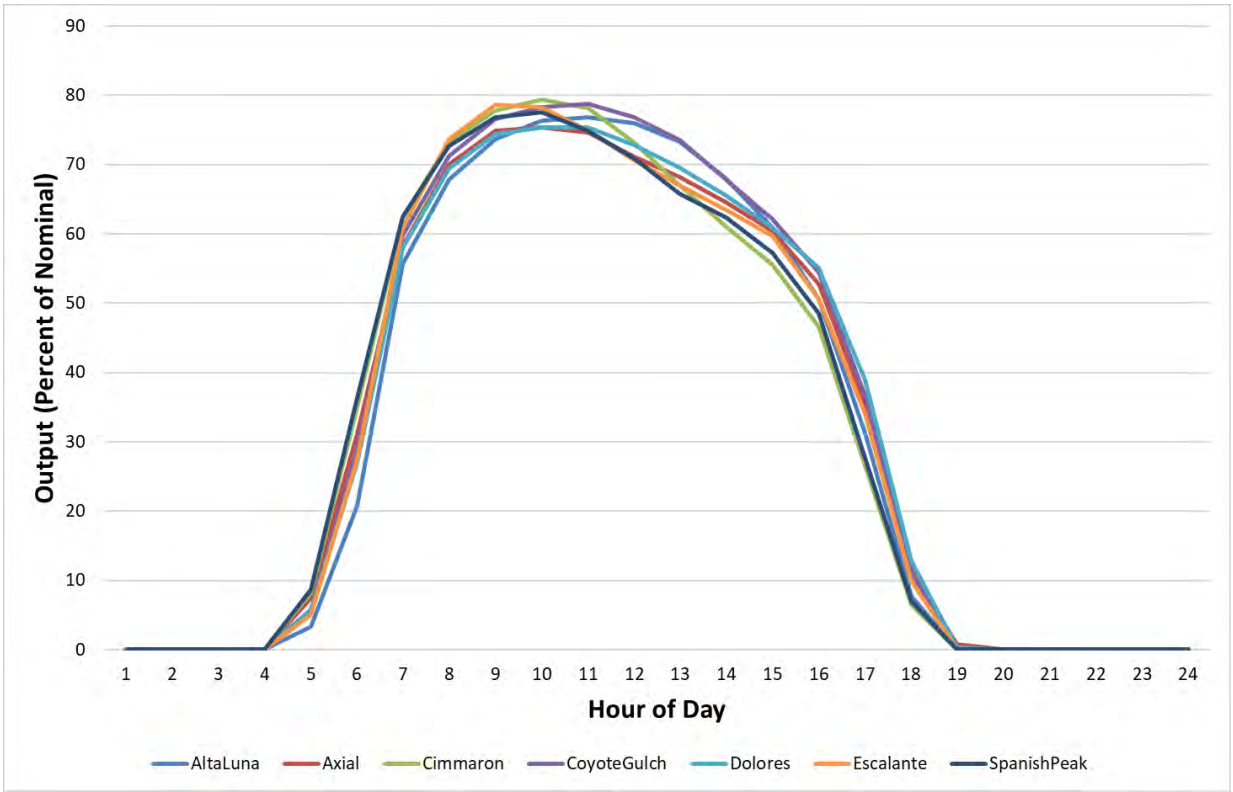


***Figure 39. Average Summer Tracking Solar Profiles***

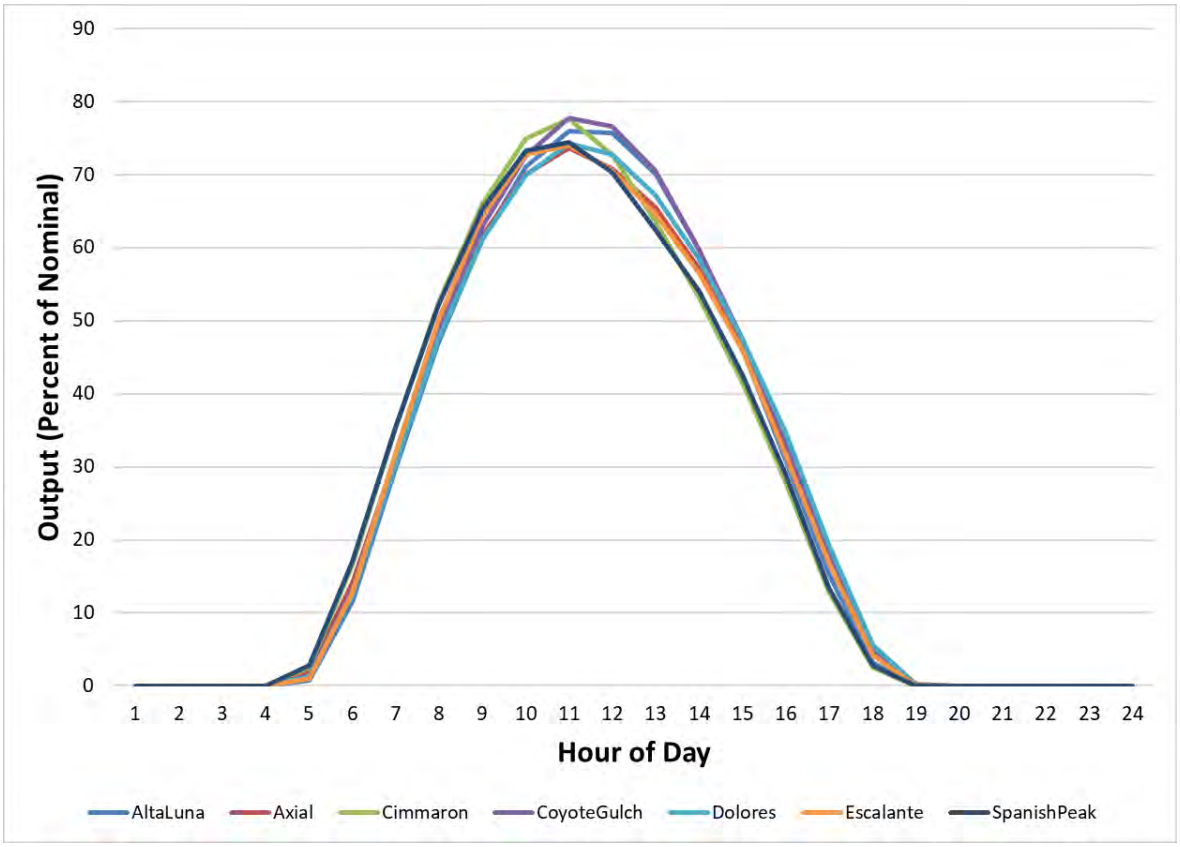


***Figure 40. Average Summer Fixed Axis Solar Profiles***

## WIND RESOURCE MODELING

TSGT has six existing/planned wind resources as well as 200 MW of unspecified future wind capacity as indicated in the table below.

***Table 11. TSGT Wind Resources***

| Unit Name | Capacity |
|---|---|
| **Carousel** | 150 |
| **Colorado Highlands** | 94 |
| **Crossing Trails** | 104 |
| **Kit Carson** | 51 |
| **Niyol** | 200 |
| **Twin Buttes** | 75 |
| **Unspecified Wind** | 200 |

All of the existing wind is located in Colorado, while the new wind is anticipated to be in the Tri-WYWNE load zone (assumed for modeling purposes to be in Wyoming).

These projects were modeled assuming a single aggregate wind profile for Colorado and a single aggregate wind profile for Wyoming.

Synthetic wind profiles were developed using NREL's SAM tool for the years 2007-2014. Multiple coordinates were used per profile in each state and were combined to create an aggregate profile per state. NREL data, however, does not always accurately represent historical production data, especially during times of peak load output. Therefore, the NREL profiles were benchmarked using wind production data that was obtained from the EIA.gov website. For Colorado, wind data was downloaded and aggregated for the PSCO BAA. For Wyoming, wind data was downloaded and aggregated for the WACM BAA. The benchmarking process included two primary adjustments to the profiles. The first adjustment was to the overall shape of the profiles so that the aggregate load duration curves matched those of the downloaded production data. The second adjustment was to ensure that the output during peak load times was consistent with the historical data.

The following figures show the monthly output profiles in percent of nominal capacity for Colorado and Wyoming wind projects, respectively.

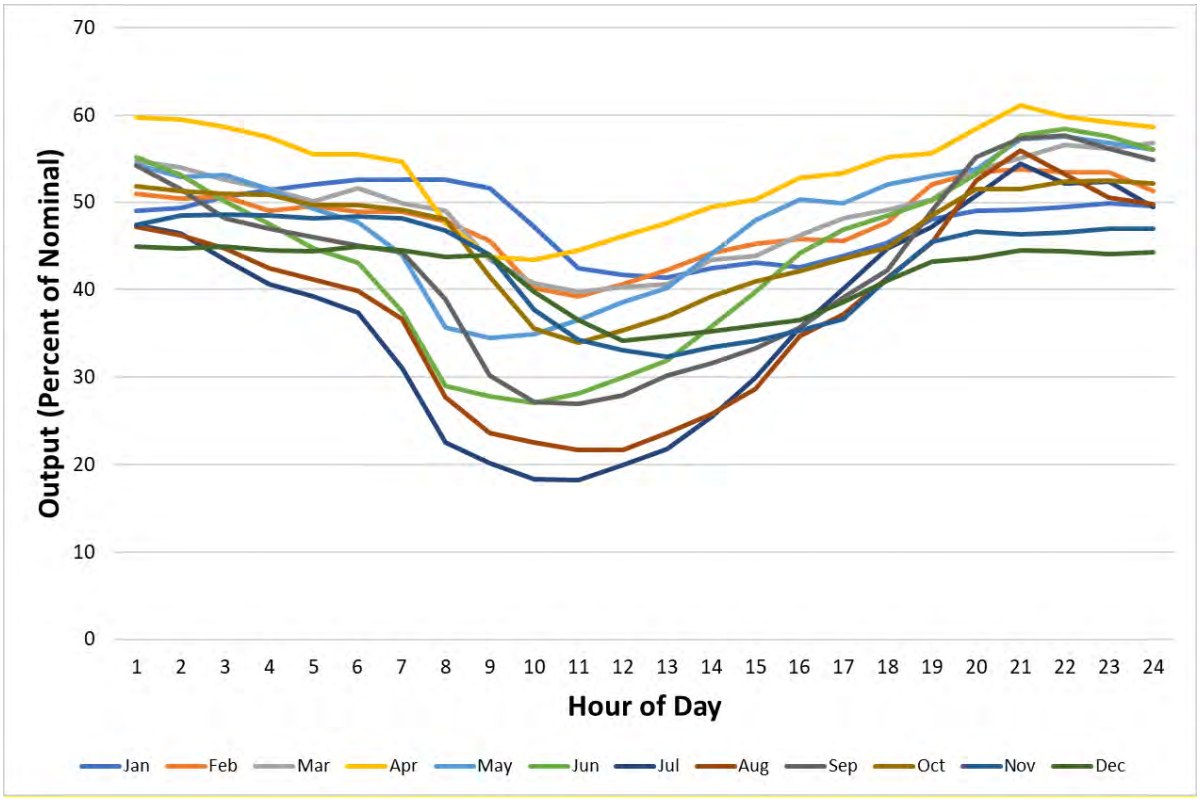


***Figure 41. Colorado Wind Profiles***

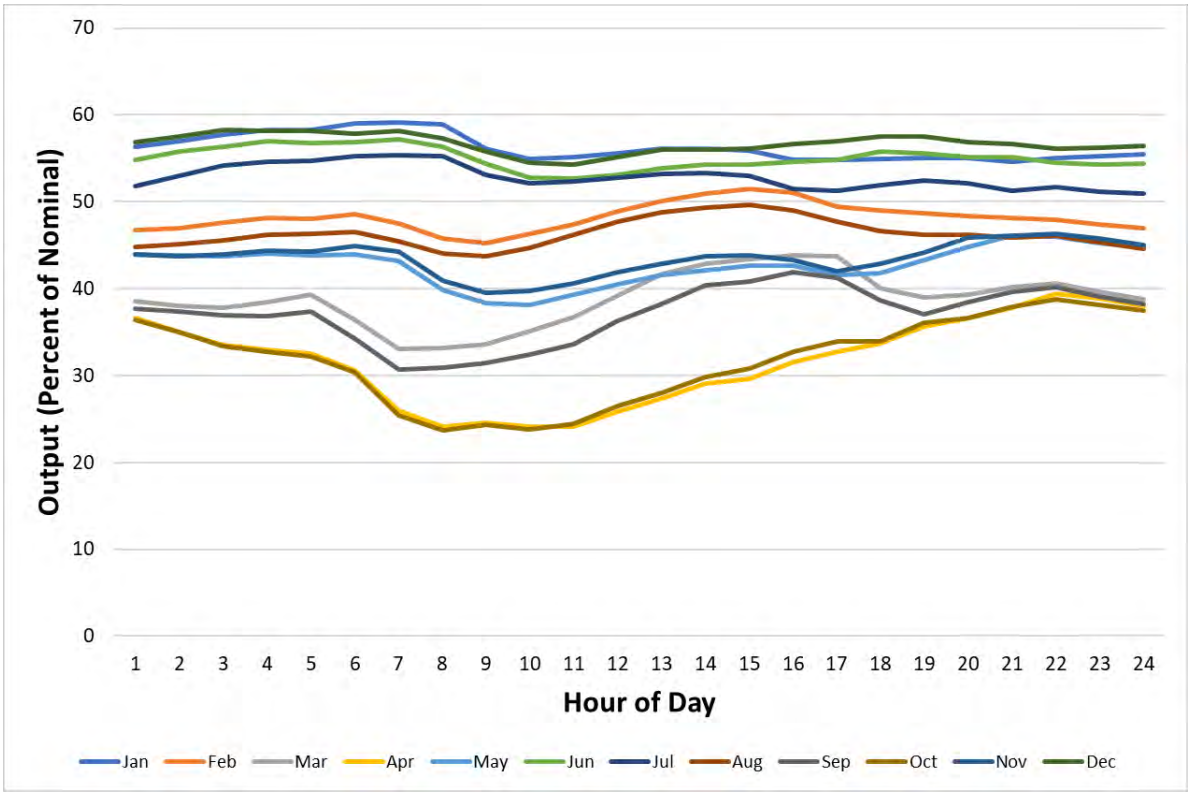


***Figure 42. Wyoming Wind Profiles***

As with the solar units, individual projects were further adjusted to match the project's historical capacity factor using the ILR. Future capacity was assumed to have a capacity factor of 45% and its ILR was set accordingly. The table below shows the capacity factors and associated ILRs for modeling purposes for each of the TSGT wind projects.

***Table 12. TSGT Wind Historical Capacity Factors and ILRs***

| Unit Name | Historical CF | ILR |
|---|---|---|
| **Carousel** | 47.8% | 1.090 |
| **Colorado Highlands** | 44.2% | 1.008 |
| **Crossing Trails** | 46.3% | 1.055 |
| **Kit Carson** | 39.3% | 0.895 |
| **Niyol** | 44.3% | 1.010 |
| **Twin Buttes** | 47.4% | 1.080 |
| **Unspecified Wind** | | 1.000 |

## STORAGE RESOURCE MODELING

TSGT does not have any battery storage facilities procured prior to 2030. Thus, no batteries are being modeled for them as part of the Base Case. However, battery storage will be a resource option in the 2023 ERP for the resource planning period and procurements will potentially occur in the resource acquisition period, 2026 to 2031. Thus, for ELCC modeling purposes, batteries were modeled with the following characteristics.

***Table 13. Battery Storage Characteristics***

| Characteristic | Value |
|---|---|
| **Storage Capacity (hours)** | 4 |
| **Charging Capacity (MW)** | Same as Nameplate |
| **Able to Provide Ancillary Services** | Yes |
| **Cycle Efficiency (%)** | 85 |

These battery storage resources were modeled as being available for economic arbitrage. However, during times of reliability risk, the economic arbitrage schedule was allowed to deviate so that the batteries would be discharged to avoid loss of load if storage capacity was available.

Based on recent industry experiences,[6] grid-scale battery storage resources are expected to have outage rates of up to 15%, with improvements expected as operational experience improves. The long-term anticipated EFOR during hours of dispatch is expected to be in the 5% range. However, outages can occur in either charging or discharging periods, suggesting a 5% outage during both periods. For modeling purposes, therefore, to achieve a 5% overall EFOR in discharge hours, these (and all other) battery storage resources were modeled with a 10% forced outage rate applicable to both charging and discharging hours.

## HYDRO RESOURCES

TSGT has one pumped storage hydro (PSH) facility and five hydro purchase contracts from WAPA. The hydro purchase contracts are scheduled on a two-day ahead basis with a contracted minimum and maximum hourly schedule amounts varying by month and monthly available energy amounts that change by month. The Mount Elbert PSH facility and the LAP_ECO WAPA contract share the same transmission export, which is limited to the WAPA contract value. Thus, it is not possible for both facilities to produce at their maximum value simultaneously. Therefore, the PSH facility can only produce energy to the extent the LAP_ECO WAPA contract is not fully scheduled. For this reason, no capacity accreditation is given to the Mount Elbert PSH facility in the PRM calculation. All modeled hydro facilities are shown in the table below.

***Table 14. TSGT Hydro Facilities***

| Unit Name | Unit Category |
|---|---|
| **CRSP_ECO** | WAPA Purchase |
| **CRSP_NM** | WAPA Purchase |
| **CRSP_WCO** | WAPA Purchase |
| **LAP_ECO** | WAPA Purchase |
| **LAP_WYWNE** | WAPA Purchase |
| **Mount Elbert** | PSH |

## OTHER MODELING ISSUES

Due to time constraints and other factors, there were several items not specifically modeled for this evaluation that could have a minor impact on the resulting ICAP or UCAP PRM. Those items include demand response resources, incremental Beneficial Electrification (BE) load, and the Springerville

[6] See https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED, slides 41-46, with emphasis on slide 46, "Specific lessons for battery storage".

hazard agreement that provides a 100 MW back up to Springerville 3 for up to 168 hours. It is anticipated that these and any other potential modeling enhancements will be incorporated in the next iteration of the reserve marginal analysis.

## FINAL CAPACITY MIX

The figure below shows the final mix of capacity modeled for TSGT. It should be noted that BTMPV is not a resource available to TSGT and is excluded from their official load forecast. However, it is being modeled here as a resource with the forecast grossed up for the BTMPV.

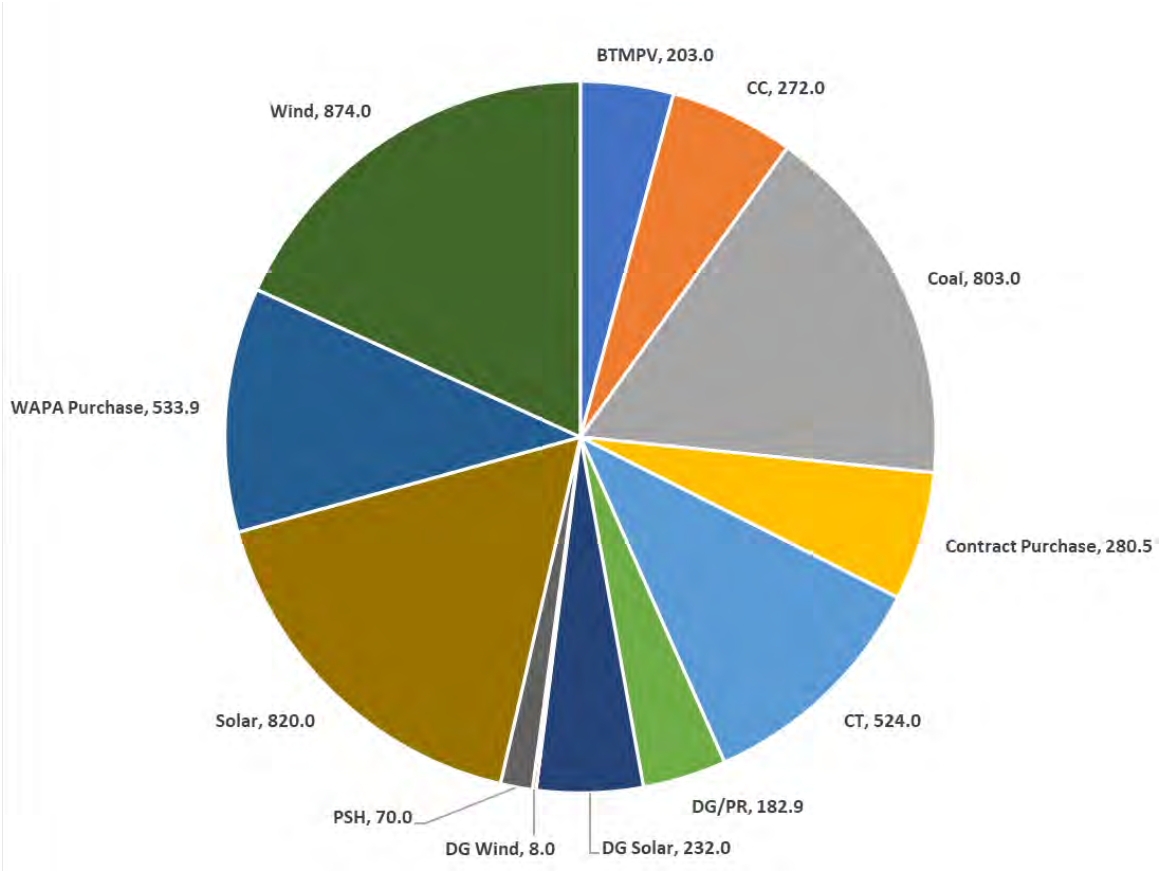


***Figure 43. TSGT Capacity Mix (MW)***

## ANCILLARY SERVICES MODEL

Per information provided by TSGT, the ancillary services model included only 64 MW of Contingency Reserve-Non Spin in Colorado (split between Tri-WCO and TRI-ECO) and 67 MW of Contingency Reserve-Non Spin in Tri-WYWNE. In addition, 3% of load was included as a load following up target. Neither had a direct impact on the PRM because no reserves were maintained during load shed events.

# STUDY APPROACH AND RESULTS

The two objectives of this study were to (a) establish the PRM for the TSGT system and (b) determine the ELCC for various penetrations of solar, wind, and BESS resources.

## DEPENDABLE CAPACITY REQUIREMENTS

The PRM for the TSGT was determined for the 2030 study year. To determine the PRM, Combustion Turbine (CT) expansion capacity was added to TSGT until the system reached 0.1 days/year LOLE. This required making multiple runs with differing amounts of expansion CTs and then trending the resulting LOLE values so that the 0.1 LOLE point could be interpolated from the results. This established the total amount of dependable capacity required to maintain a reliable system. For TSGT, 59.2 MW of capacity was needed above their existing resource portfolio, to achieve 0.1 days/year LOLE.

PRM is an accounting exercise based on the amount of dependable capacity. To perform this accounting exercise requires the determination of the ELCC of the existing portfolio of renewable resources as described in the subsection below.

## EXISTING PORTFOLIO ELCC AND RESULTING PRM

Determining the portfolio ELCC required the following steps:

1. Remove the full portfolio of solar and wind (including distributed solar and wind)
2. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE, and
3. Calculate portfolio ELCC by dividing the perfect added capacity by the nameplate capacity removed.

For the TSGT system, the total amount of renewable resources removed was 1,934 MW.[7] The analysis described above resulted in a portfolio ELCC value of 350 MW or 18.0%.

Using the nameplate of the conventional resources plus the ELCC resources plus the expansion capacity, determination of the PRM (in %) is determined as follows:

PRM = [(Conventional Capacity + ELCC Capacity + Adjustment Capacity) / Peak Load – 1] * 100.

Those calculations are shown in the table below:

[7] Because the resources are behind the meters for the load seen by TSGT or included in its load forecast, BTMPV was not included as part of the portfolio ELCC calculation.

***Table 15. PRM Calculation***

| Component | Capacity | ELCC | Equivalent Capacity |
|---|---|---|---|
| **Conventional Resources** | 2596.3 | | 2596.3 |
| **ELCC Resources** | 1934.0 | 18% | 348.1 |
| **Adjustment Capacity** | | | 59.2 |
| **Total Capacity at Target Reliability** | | | 3003.6 |
| **Coincident Peak Load** | | | 2210.9 |
| **Reserves** | | | 792.8 |
| **ICAP PRM** | | | 35.9% |

This PRM was developed using a coincident peak load that was developed as follows:

CPL = Load[8] – EE.

This PRM represents a significant increase in PRM over TSGT's current PRM requirement of 15%. One reason for the difference is in accounting. In the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Beyond the accounting, however, the key drivers in this PRM include the high EFOR of the conventional coal and CC resources as well as significant shaft risk due to the size of these units relative to the TSGT peak load. To demonstrate this impact, two additional analyses were performed. First, the ELCC of the CC and coal units were calculated. Then, a calculation was performed to demonstrate the impact on PRM if these units were smaller (aka no shaft risk) and had a considerably lower EFOR.

The table below shows the ELCC of the coal and CC units.

***Table 16. Coal and CC ELCC***

| Resource | EFOR | ELCC |
|---|---|---|
| **Shafer CC** | 7.8% | 64.4% |
| **Springerville Coal** | 9.2% | 63.8% |
| **Laramie River Coal** | 9.3% | 58.8% |

[8] For purposes of PRM calculation, load was reduced for customer BTMPV consistent with TSGT's forecasting process.

These are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

***Table 17. Impact of High EFOR and Shaft Risk***

| Component | ELCC | MW | Impact |
|---|---|---|---|
| **CC** | 64.4% | 272 | 175.168 |
| **SPV** | 63.8% | 319 | 203.522 |
| **LRS** | 58.8% | 484 | 284.592 |
| **Weighted** | 61.7% | 1075 | 663.282 |
| **Target ELCC** | 90.0% | 1075 | 967.5 |
| **Impact MW** | | | 304.2 |
| **Base Case Reliable MW** | | | 3003.6 |
| **Adj for EFOR/Shaft Impact** | | | 2699.4 |
| **Coincident Peak Load** | | | 2210.9 |
| **PRM** | | | 22.1% |

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

To demonstrate the relationship between reserve margin and LOLE visually, the figure below shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE falling at a reserve margin of ~35.9%.

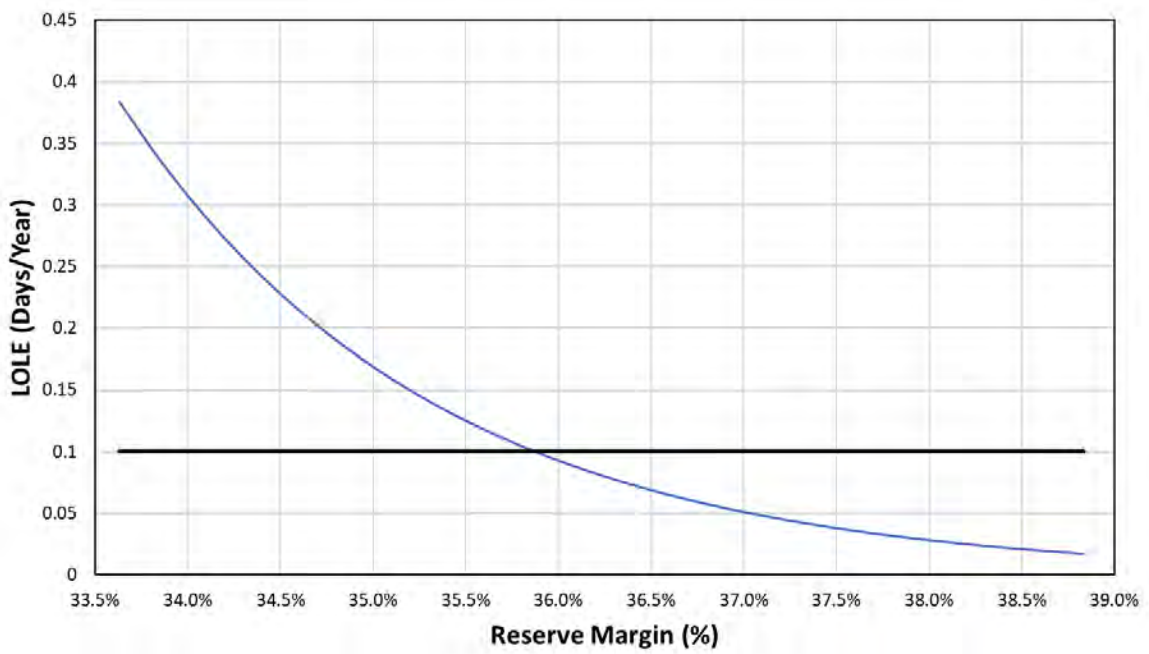


***Figure 44. LOLE Analysis***

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system EFOR resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. Given the current environment of increasing penetrations of renewable resources, that means PRM is expected to change over time.

An alternative accounting approach that attempts to stabilize the PRM by removing the effects of average forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by 1-EFORd for the conventional resources. The table below shows the UCAP Capacity for the TSGT conventional resources.

***Table 18. TSGT UCAP Capacity***

| Unit Category | Nameplate MW | 1-EFORd | UCAP MW |
|---|---|---|---|
| **CT** | 524.0 | 96.9% | 507.5 |
| **CC** | 272.0 | 93.7% | 254.8 |
| **Coal** | 803.0 | 89.4% | 717.8 |
| **UCAP Resources** | 1599.0 | 92.6% | 1480.1 |

The table below shows the base case PRM assuming UCAP accounting using the UCAP capacity from above.

***Table 19. Base Case UCAP PRM Accounting***

| Component | Capacity | UCAP/ ELCC | Equivalent Capacity |
|---|---|---|---|
| **Firm Resources** | | | 997.3 |
| **UCAP Resources** | 1599.0 | 92.6% | 1480.1 |
| **ELCC Resources** | 1934.0 | 18.0% | 348.1 |
| **Adjustment Capacity** | | | 59.2 |
| **Total Capacity at Target Reliability** | | | 2884.6 |
| **Coincident Peak Load** | | | 2210.9 |
| **Reserves** | | | 673.8 |
| **ICAP PRM** | | | 30.5% |

However, EFOR (and EFORd) is based upon the average outage rate of the resource fleet. There are times when actual outages are higher than average and other times when they are lower than average. This creates an asymmetry in the outage profile, resulting in a true contribution to reliability that is less than the UCAP capacity. As such, UCAP accounting still results in a PRM that can change with significant changes to the system mix and penetration of renewable resources.

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and represent the same portfolio. The only difference is in the PRM accounting.

Because of this significant shaft risk, LOLE is being driven by outages as much as weather or load. As such, LOLE is expected across all weather years as demonstrated in the figure below.

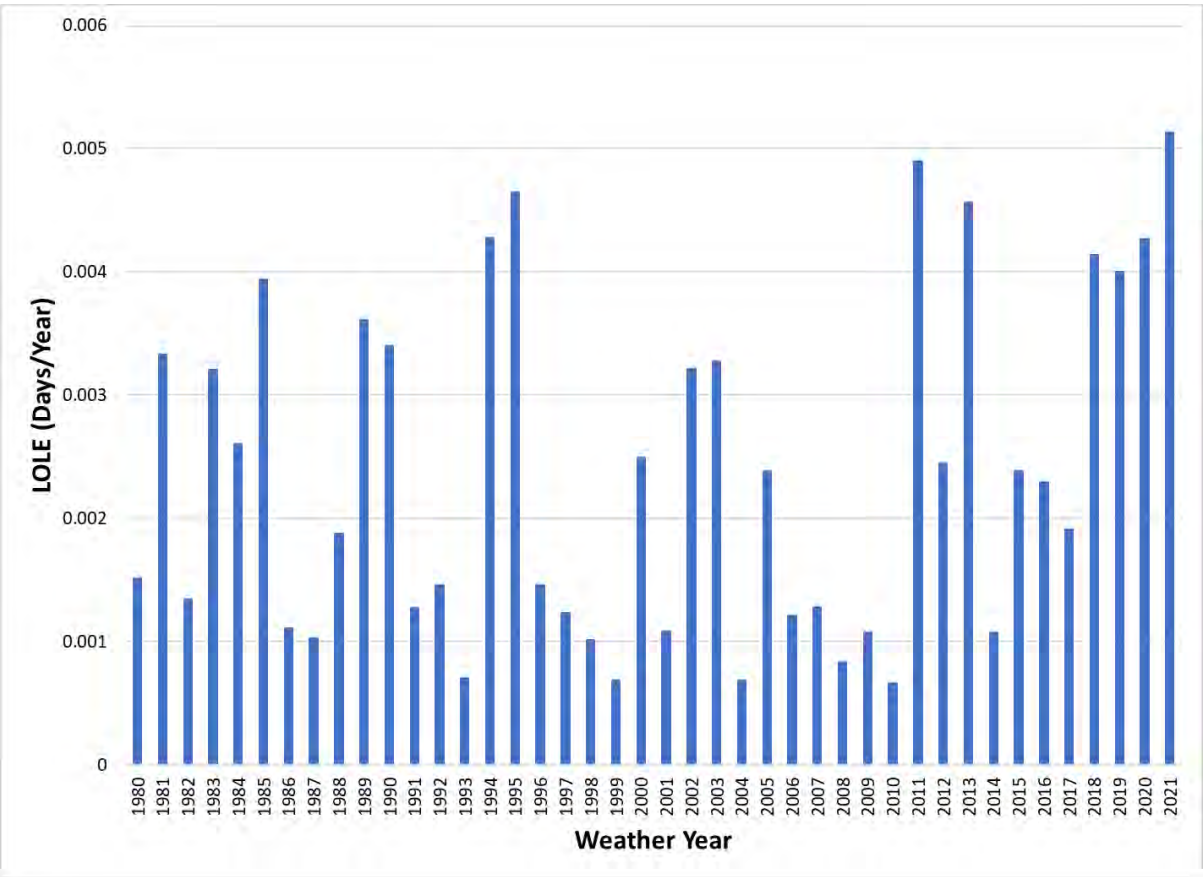


***Figure 45. LOLE by Weather Year at PRM***

To demonstrate the risk of loss of load by season, the figure below shows the breakdown of loss of load expectation by month. As the figure shows, the majority of the reliability risk for TSGT occurs in the summer months, although there is some risk in all months due to the shaft risk exposure associated with forced outages.

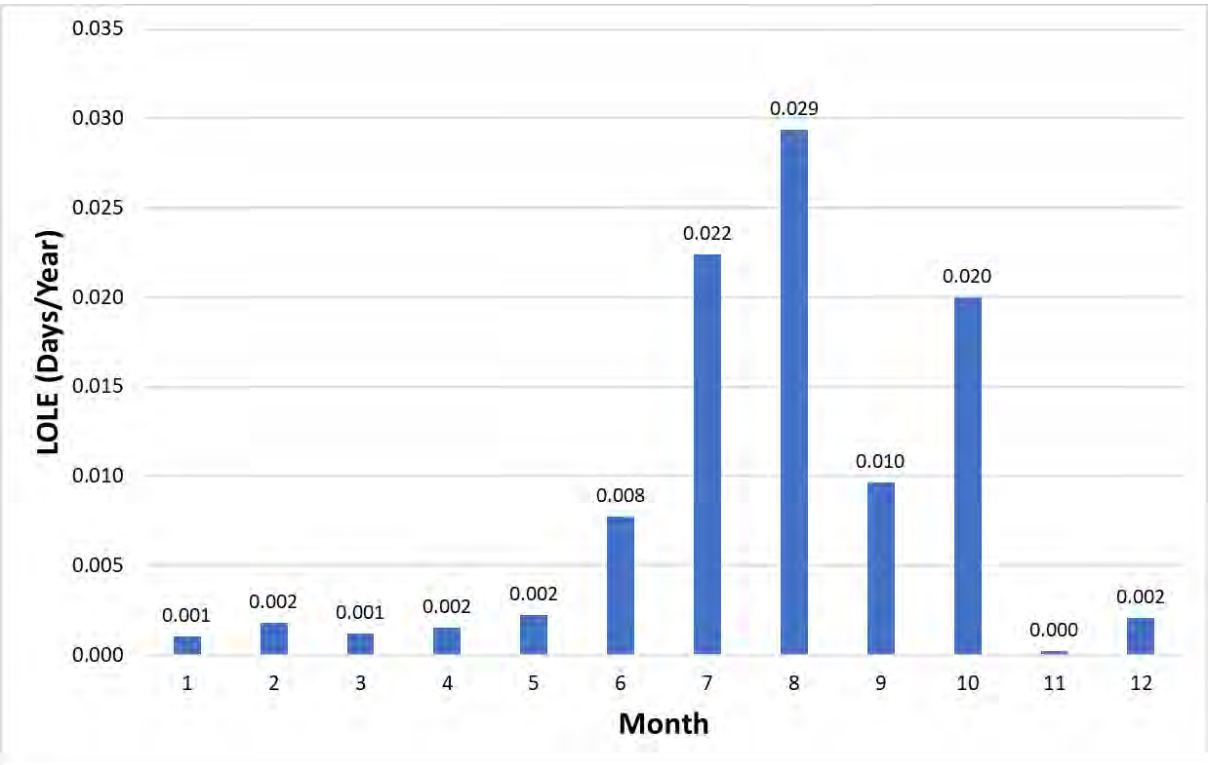


***Figure 46. LOLE by Month at PRM***

## PRM RECOMMENDATION

Based on this analysis and based on TSGT's decision to use UCAP accounting for PRM purposes, a UCAP PRM of 30.5% is recommended. However, given the transitional period prior to 2030 in which departing member load has not yet left the system and coal units have not yet retired, a transitional PRM consistent with the shaft-risk and EFOR adjusted ICAP PRM of 22% can be supported.

## TECHNOLOGY SPECIFIC ELCC

In addition to the base case portfolio ELCCs needed for the PRM calculation, analyses were performed to calculate average and marginal ELCCs by technology for solar, storage, and wind up to the following penetrations:

- Solar – 2,000 MW
- 4-hour Battery – 1,000 MW
- Wind – 2,000 MW

These ELCCs were first calculated within SERVM for a subset of penetrations according to the following matrix. SERVM runs were made for solar and battery combinations represented by the X marks for wind penetrations of 0 MW, 500 MW, 1,000 MW, 1,500 MW and 2,000 MW. The blue X mark was not run for the 0 MW wind penetration. The green X marks were only run for the 0 MW wind penetration.

***Table 20. Matrix of SERVM ELCC Runs***

| Solar (MW) \ Battery Storage (MW) | 0 | 100 | 250 | 500 | 750 | 1000 |
|---|---|---|---|---|---|---|
| 0 | X | X | X | X | X | X |
| 250 | X | | | | | |
| 500 | X | | | | | |
| 750 | X | | | | | |
| 1000 | X | | | X | | X |
| 1250 | X | | | | | |
| 1500 | X | | | | | |
| 1750 | X | | | | | |
| 2000 | X | | | X | | X |

For purpose of developing this matrix, the BTMPV, customer distributed solar, and customer distributed wind were all considered pre-existing (i.e., underlying the test system), such that these penetrations would be considered incremental to those underlying penetrations of solar and wind.

Using pyramid smoothing techniques, this series of matrices were then expanded into a large three-dimensional dense matrix containing total portfolio values for any combination of solar, wind, and battery penetrations up to the specified maximum penetrations.

In addition to these solar, battery, and wind scenarios, additional scenarios were evaluated to determine the ELCCs for each of the following:

1. Customer Distributed DG,
2. Energy Efficiency, and
3. 10-hour Batteries.

## ELCC METHODOLOGY

To determine the average ELCC for each of these scenarios, each scenario was evaluated in accordance with the following steps.

1. Develop a reference case for the scenario set (e.g., all the matrix solar/battery/wind scenarios used the same reference case)

a. Remove the technology class(es) being evaluated (e.g., remove all existing solar, battery, and wind resources).
b. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE.

2. For each scenario, add back the penetration of the technology class(es) being evaluated (e.g., for the 500 MW solar scenario, add back 500 MW of solar).
3. Iteratively remove perfect capacity until the system returns to 0.1 days/year LOLE.
4. Divide the total amount of capacity added by the amount of perfect capacity removed to get the average ELCC for the scenario.

## ELCC RESULTS

The result of this pyramid smoothing associated with the sparse matrix of SERVM ELCC values was a dense three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the range of penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any desired penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

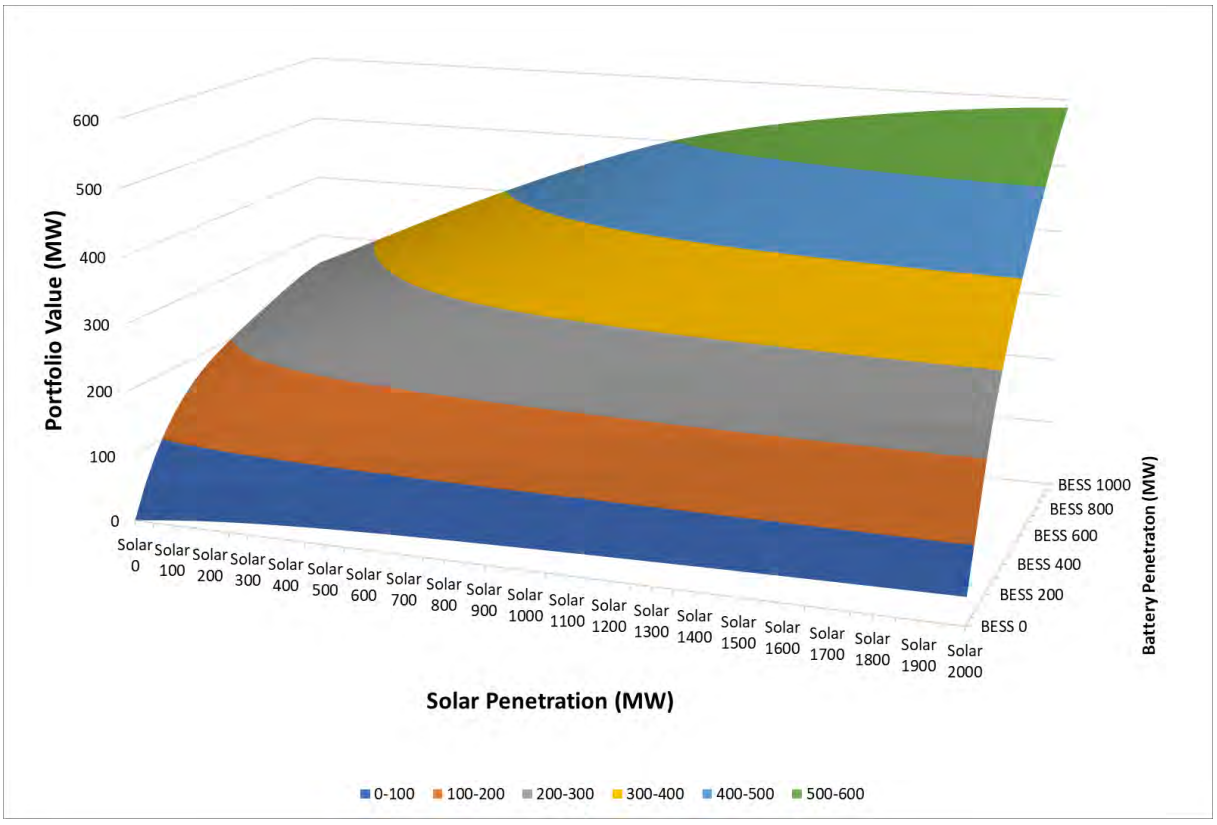


***Figure 47. Portfolio Capacity Value at Zero Wind Penetration, Illustrative***

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind.

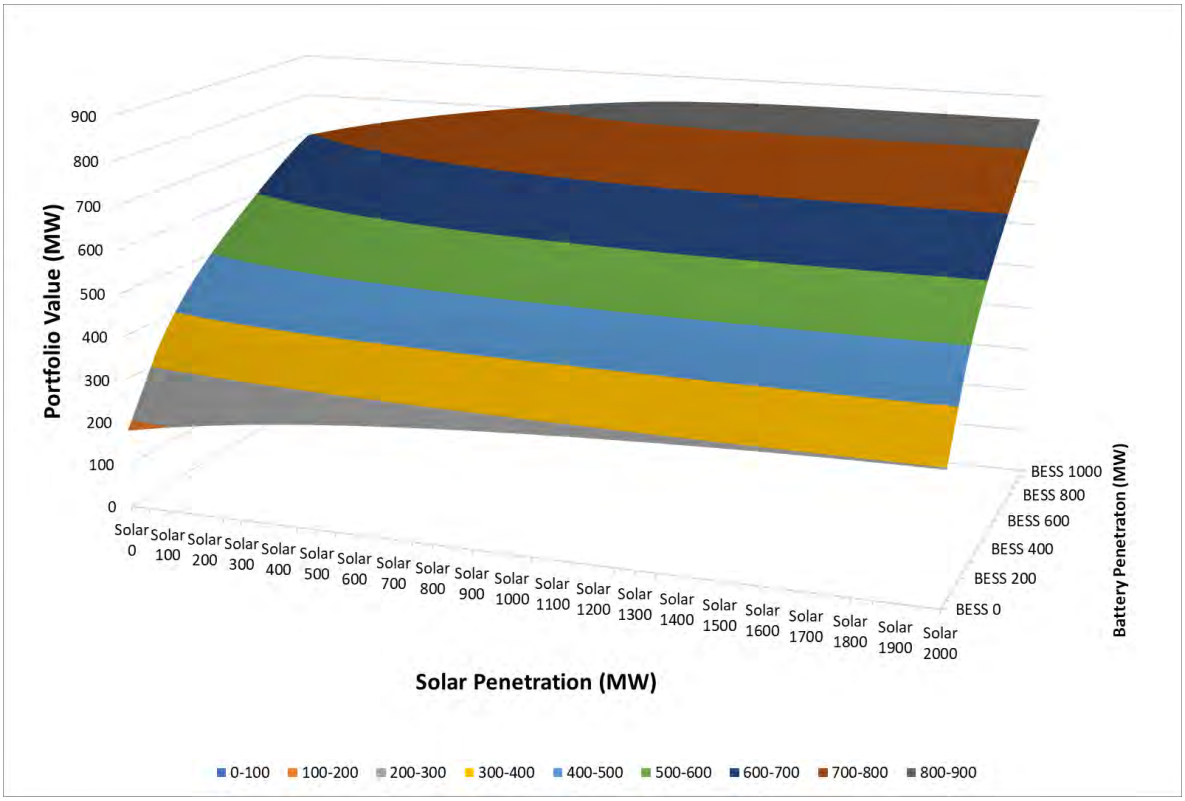


***Figure 48. Portfolio Capacity Value at 2000 MW of Wind, Illustrative***

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for

the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries. For example, in the solar chart, wind is at 1,000 MW and batteries are at 500 MW.

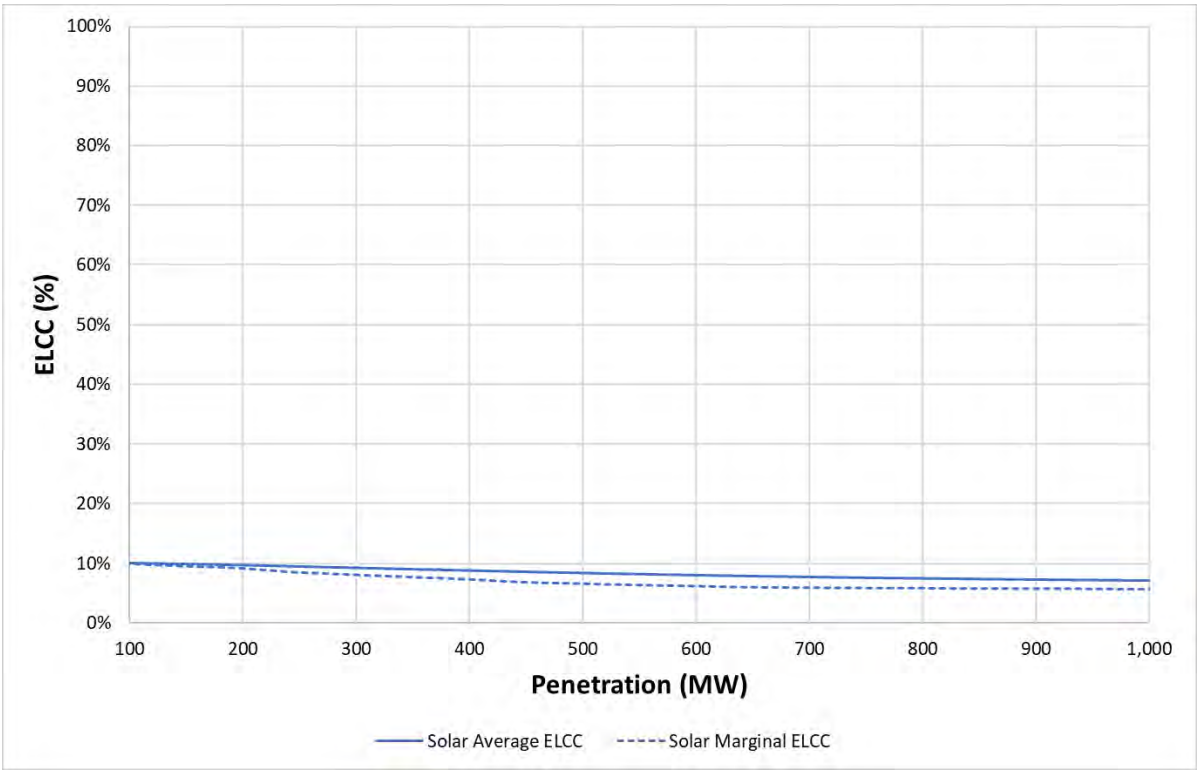


***Figure 49. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery***

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

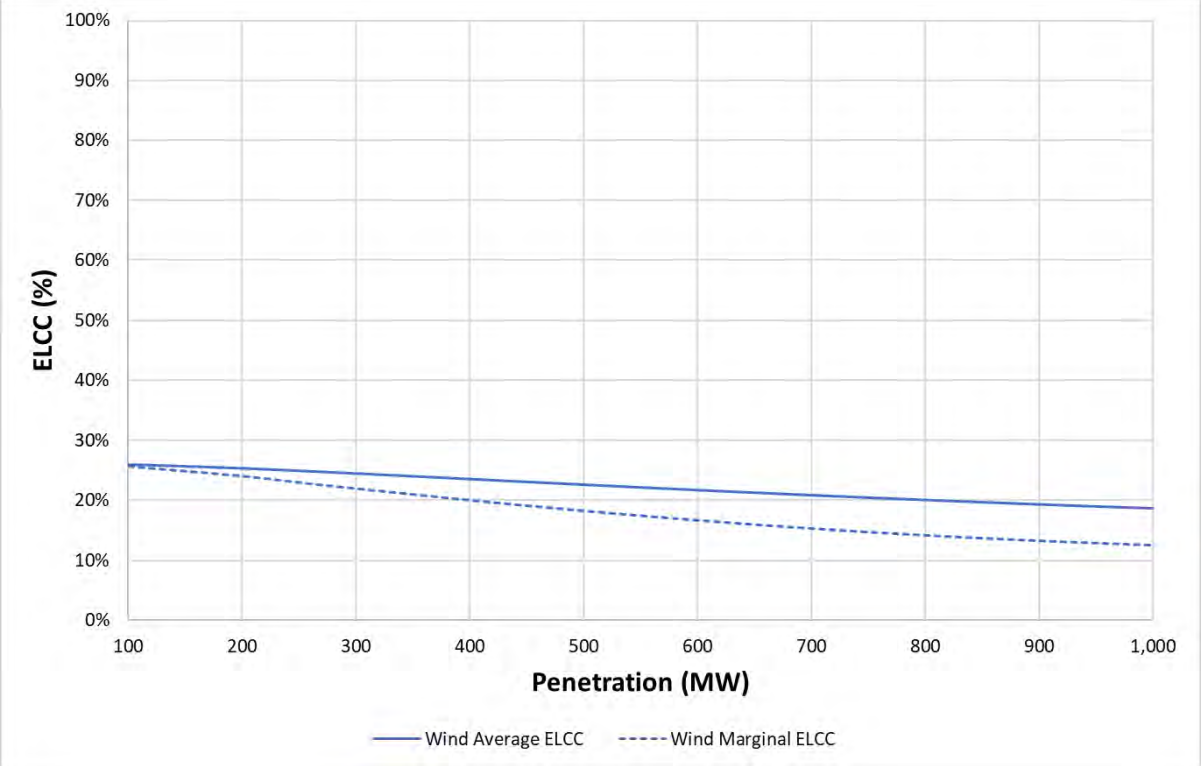


***Figure 50. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery***

Finally, the battery chart is shown below.

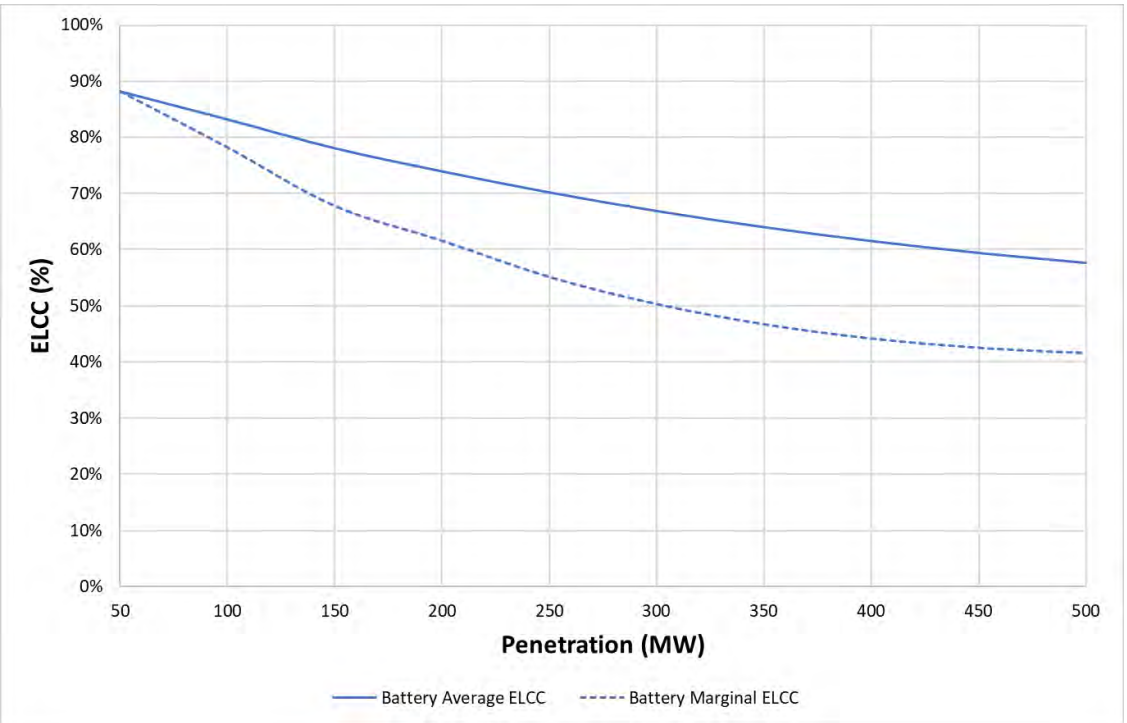


***Figure 51. Battery ELCC at 1,000 MW of Solar and Wind***

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including customer DG solar, EE, and 10-hour batteries.

To determine the ELCC of the customer DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the customer DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be "first in the queue" relative to the TSGT solar.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The figure below shows the average ELCC for 10-hour batteries for each of the three penetrations evaluated.

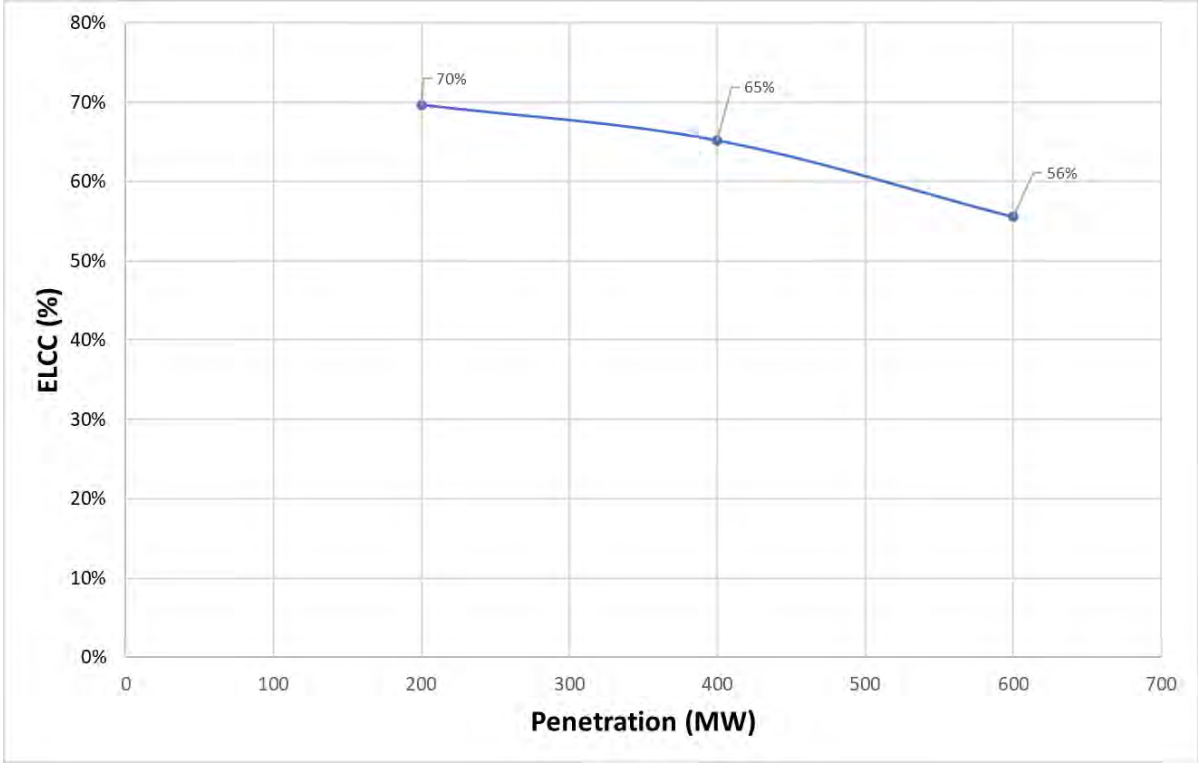


***Figure 52. 10-Hour Battery Average ELCC***

# CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

# APPENDIX

## PCAP PRM Accounting

Neither ICAP nor UCAP truly reflect the reliability contributions of conventional resources (i.e., is not a perfect capacity equivalent) as evidenced by the ELCC calculations of the coal and CC resources in the results section above. Variability in outages results in some peak days having higher than average outages, resulting in a larger disparity between the true reliability contribution of the conventional fleet and the implied reliability contribution of EFORd. For TSGT in particular, shaft risk also contributes, because of the size of its coal and CC units relative to the peak load. Furthermore, UCAP does not stabilize the PRM against changes in renewable penetration. The most stable PRM accounting, therefore, utilizes PCAP accounting, in which all resources are discounted by their perfect capacity equivalent, or their ELCC. The table below shows the base case PRM assuming PCAP accounting. Only load is considered since EE would be treated as an ELCC modifier similar to resources.

***Table 21. 2026 Base Case PCAP Accounting***

| Unit Category | MW |
|---|---|
| **Total PCAP Capacity** | 2350.9 |
| **Coincident Peak Load** | 2221.3 |
| **Reserves** | 129.5 |
| **PRM** | 5.8% |

## Solar Modeling

The table below shows the GPS coordinates for each of the nine existing sites.

***Table 22. Solar GPS Coordinates***

| Unit Name | GPS Coordinates |
|---|---|
| **Alta Luna** | 32.57, -107.46 |
| **Axial** | 40.3, -107.77 |
| **Cimarron** | 36.47, -104.63 |
| **Coyote Gulch** | 37.04, -108.02 |
| **Dolores Canyon** | 37.71, -108.75 |
| **Escalante** | 35.42, -108.09 |
| **San Isabel** | 37.37, -104.48 |
| **Spanish Peaks 1** | 37.38, -104.46 |
| **Spanish Peaks 2** | 37.38, -104.45 |

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit PP: Department, Order No. 202-25-10 (Nov. 25, 2025)

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**Department of Energy**
Washington, DC 20585

**Order No. 202-25-10**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

***Order Nos. 202-25-4 and 202-25-8***

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[7]

***Continuing Emergency Conditions***

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[5] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id.*

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[21] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[22]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.
[16] *Id*.
[17] *Id.* at 16, Table 1.
[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[19] *Id*.
[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").
[21] *Id.* at 14.
[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[23] *Id*. at P 10.
[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[32] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[33]

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[25] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[35] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

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[34] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[35] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[36] *See* Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[37] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy, at 28 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[41] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

## ***ORDER***

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).
[44] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Pennsylvania Public Utility Commissioners**
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | ) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit QQ: Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)

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# U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days

(December 31, 2025 – Westminster, Colorado) Tri-State Generation and Transmission Association and the other utilities that co-own Craig Generating Station Unit 1 received an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Pow Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement.

Separately, Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve, and Tri-State and the other co-owners will need to take the necessary steps to repair the valve in a timely manner.

"Tri-State has a policy of 100% compliance, and we will work with Unit 1 co-owners, and federal and state governments to determine the most cost-effective path to that end," said Duane Highley, Tri-State CEO. "We are continuing to review the order to determine what this means for Craig Station employees and operations, and the financial impacts. As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options."

As a result of the order, retaining Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State is continuing to review the order to determine how best to comply while limiting the costs to its members, and the impacts to its employees and operations.

The retirement of Craig Unit 1 was specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits, and the Regional Haze State Implementation Plan put in place in 2016. Tri-State's 2020 and 2023 Electric Resource Plan (ERP) modeling reflected the previously announced retirement date for Unit 1. The model results of the 2023 ERP showed adequate resources to maintain reliability on Tri-State's system following the retirement of Craig Station.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1's capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Tri-State will share more information as appropriate when available.

## About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

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Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State's plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State's filings with the Securities and Exchange Commission. Tri-State's expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

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| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit RR: Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)

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# 1 coal plant open amid order



**Rebecca Powell**
Fort Collins Coloradoan

Jan. 6, 2026, 5:02 a.m. MT

Platte River Power Authority's general manager says he disagrees with a federal order requiring one of the coal plants it owns a stake in to remain open past its scheduled retirement and is waiting to learn what it might cost Fort Collins' wholesale electricity provider.

The U.S. Department of Energy on Dec. 30 issued an emergency order requiring Craig Unit 1 in Moffat County to remain available to operate for at least the next 90 days at the direction of the Western Area Power Administration or Southwest Power Pool West.

The plant was set to be retired on Dec. 31 after 45 years of operation, until that order was issued only a day prior.

PRPA is a joint owner of the plant with PacifiCorp, Xcel Energy, Salt River Project and Tri-State Generation and Transmission, which operates the facility.

PRPA owns 18% of the Craig 1 and 2 coal units.

The nonprofit provides wholesale electricity to Fort Collins Utilities. It is owned by four Northern Colorado cities: Fort Collins, Loveland, Longmont and Estes Park.

The Department of Energy's emergency order contends there is a shortage of electric energy and facilities in the Western Electricity Coordinating Council Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

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region have been retired, with more retirements planned.

Wright cites supply chain issues with building battery storage systems to help replace the energy from those retirements.

The emergency order also cited two executive orders from President Donald Trump. One declared a national energy emergency due to "insufficient energy production, transportation, refining, and generation." The other declares the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, like the expansion of AI data centers and domestic manufacturing.

But PRPA General Manager and CEO Jason Frisbie says PRPA does not need the Craig 1 unit because it has already replaced the energy that came from it.

“We have planned for the retirement of Craig Unit 1 for nearly a decade and have proactively replaced the capacity and energy from new sources," Frisbie said in a statement provided to the Coloradoan.

The joint owners have been planning for the plant's closure since 2016 "for economic reasons and to comply with numerous state and federal requirements," a Dec. 31 news release from Tri-State states. "This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit’s retirement."

The state of Colorado is requiring utility providers to cut their 2005 carbon emissions by 80% by 2030.

The Craig 1 plant hadn't been operating since a mechanical failure occurred on Dec. 19, according to Tri-State. The problem will have to be fixed for it to become available for operations.

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Duane Highley, Tri-State CEO, said the not-for-profit cooperative's membership will bear the costs of compliance "unless we can identify a method to share costs with those in the region."

"There is not a clear path for doing so, but we will continue to evaluate our options," Highley said.

Frisbie said PRPA is working to understand the impacts.

"While we disagree with the need to keep the plant open, we are working with the unit’s operating agent, Tri-State Generation and Transmission, and the other owners to understand the compliance requirements and cost obligations of the emergency order," he stated.

PRPA is set to retire its last coal plant, Rawhide 1, located north of Fort Collins, at the end of 2029.

At that point, PRPA expects 88% of its energy will be from noncarbon sources. Today that figure is around 36%.

To help fill the void, PRPA is expected to invest $600 million in construction of five aeroderivative gas turbines to provide electricity when wind and solar resources aren't available due to the weather.

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UNITED STATES OF AMERICA
BEFORE THE
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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | ) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit SS: Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6, 2026)

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ENERGYWIRE

# PJM to ratchet down projected AI power demand for eastern US

## An updated analysis from the regional grid operator is expected to provide a reality check on data center growth.



BY: **PETER BEHR** | 01/06/2026 06:53 AM EST



A data center is seen under construction last year near the Susquehanna nuclear power plant in Pennsylvania.| Ted Shaffrey/AP

**ENERGYWIRE |** Across the U.S., energy policymakers and power grid operators have three broad goals at the top of their 2026 priority lists: enable AI dominance. Secure electricity supply. Keep power prices from spiraling.

But hitting those targets is challenged by a simple question that remains hard to answer: What's real and what's hype when it comes to data center demand for electricity?

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The dilemma is front and center at PJM Interconnection, the nation's largest regional power grid, serving 67 million people in 13 states from the Atlantic coast to Chicago. Later this month, PJM plans to release an updated estimate of future electricity demand from large users. The report is expected to provide a serious reality check to the projections that developers and utilities make about future data center growth.

PJM Chief Operating Officer Stu Bresler said last month that PJM's overall power demand forecast for the year beginning in mid-2027 will be "appreciably lower" than current projections. PJM wants more evidence on how fast and how large new data centers can actually be built with shortages of chips, electronics and specialized construction teams.

Overestimating AI data center growth threatens to burden consumers with billions of dollars in excessive investments. Underestimating it increases risks of power shortages and blackouts while also undercutting current U.S. leadership as a developer of AI technology.

"At a time when utilities forecast hundreds or thousands of megawatts of growth, improving forecasts by even a few percentage points in the right direction — up or down — can impact billions of dollars in investments and customer bills," said David Rosner, a member of the Federal Energy Regulatory Commission, last year.

"Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible," Rosner said.

The most detailed analysis of future U.S. data center demand, issued a year ago by the Department of Energy's Lawrence Berkeley National Laboratory, could not get close to a precise prediction. Instead, it estimated the amount of the U.S. electricity output consumed by data centers in 2028 could range anywhere from 6.7 percent to 12 percent.

"We're all going around trying to solve a problem that we haven't even defined yet," said Caitlin Marquis, managing director of Advanced Energy United, a coalition of clean technology developers and energy users. "It's definitely worthwhile making sure that we know what we're planning for, because the costs of getting that wrong are significant either way."

But a clearer picture may be clouded by consumer resistance that puts some data center projects in doubt, and a fight in Washington over the power of the states to regulate AI.

President Donald Trump's executive order in October declares global AI "dominance" to be a national security imperative and seeks to impose White House control over state AI policymaking.

Governors from both political parties who head AI-leading states oppose Trump's moves. But governors have also been among the biggest AI cheerleaders because of the investment and tax dollars and jobs data centers deliver.

Acting on a directive from the Department of Energy, FERC is trying to forge new rules for assessing data center growth, with an uncertain timetable. PJM is a test case in the debate because of its concentration of existing data centers, the largest in the world by industry estimates.

## Forecasts that 'defy logic'

PJM's long-term forecast projected an unprecedented surge in peak power use by data centers, factories and cryptominers that would require adding 32,000 megawatts of new generation, batteries, and demand response between 2024 and 2030. Of this, PJM expected 30,000 MW to come from data centers.

PJM's total generating capacity increased by only about 2,000 MW, or 1 percent, in the past year.

PJM's demand forecasts have been amped up by tech companies plowing billions of dollars into the AI race, joined by investor-backed speculators seeking to secure marketable sites for new centers, according to participants in PJM's review.

The prospect of skyrocketing electricity demand is already showing up on utility bills, according to PJM's independent market monitor, Joseph Bowring of Monitoring

Analytics. PJM charges ratepayers for incentive payments to generators to keep plants operating in future years, and those payments have escalated in the past two years because of expected data center construction.

Kent Chandler, a senior fellow at the R Street Institute and a former Kentucky utility regulator, said some PJM officials have acknowledged privately to him that the forecasts coming from utilities “sort of defy logic.”

“There just aren’t enough transformers and conductors and towers and engineers to accommodate the load growth that some of these utilities are proposing,” Chandler said.

That’s true not just within PJM, he said, but across the country.

Potential roadblocks to data center projects are detailed in a new analysis by ICF International. The consulting firm's software mapping program identifies potential data center sites based on key factors like the availability of grid power, favorable zoning and fiber-optic networks. The list of prime data center project locations is shrinking rapidly in Northern Virginia and many other areas, the ICF analysis shows.

“The challenge is knowing which data center is real versus a phantom project,” said Himali Parmar, ICF vice president for energy markets.

Developers are making multiple applications for the same project because it’s relatively cheap to do so, she said. Their applications are shielded by confidentiality agreements that developers demand and utilities accept rather than get in arguments with a potentially huge customer.

“Am I looking at 40 gigawatts of new load requests, or is it 70, or is it 80? That’s a challenge with this lack of transparency,” she said. “PJM does not know what’s coming its way.”

“Utilities have an inherent financial bias to overstate demand” in their forecasts, Chandler said. Strong demand forecasts can move utilities’ stock prices higher and result in increased investment in grid infrastructure that boosts financial returns, grid experts explain.

PJM officials “don't feel comfortable with what utilities are putting in,” Chandler said. “They don't necessarily have the information or expertise [to contradict the utility forecasts]. That’s something they're figuring out now,” Chandler added.

An advance clue to the revisions PJM is preparing may be data from the preliminary report on load growth PJM published last year — the report that will be updated this month.

It showed some utilities in PJM making significantly different assumptions about the reality of utilities' data center power demand.

An example is the contrast in load growth forecasts from Allentown, Pennsylvania-based PPL Corp., and Dominion Energy Inc., the Richmond, Virginia, power company. Dominion serves "data center alley" in Northern Virginia, the largest cluster of the facilities anywhere. Northeast Pennsylvania, PPL's territory, is seeing a rush of AI data center development proposals.

PJM published two forecasts. One was a "capacity" figure based on developers' unverified requests for transmission capacity within PJM to manage the load growth the developers are projecting. The second forecast was the utilities' own estimate of actual load growth.

PPL capacity forecast shows demand soaring more than 3,000 percent to 13,412 MW, in 2029. PPL's own demand estimate indicates that PPL expects about 80 percent of that new data center construction to be completed by 2029.

Dominion, on the other hand, which has the most experience within PJM by far with its track record of data center construction, said that only about 30 percent of the developers' power requests will actually materialize in 2029.

An analysis by ClearView Energy Partners said PJM is very likely to require better forecasting by utilities of data center demand. Its analysts noted that PJM board chair David Mills has suggested PJM could require state officials to review utilities' power demand forecasts and may call for scrutiny of forecasts by outside analysts looking at crucial supply-chain issues that could slow new data center construction.

"We would be better off if operators like PJM got the information directly from the customer and could have a back-and-forth with them to fully understand what they're doing," Chandler said.

UP NEXT IN **THIS EDITION OF ENERGYWIRE**

Congress would boost oil and gas spending in fiscal 2026 package

BY IAN M. STEVENSON



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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | ) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit TT: Department, Order No. 202-26-21 (Mar. 30, 2026)

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**Department of Energy**
Washington, DC 20585

**Order No. 202-26-21**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain[3] assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

## *BACKGROUND*

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[4] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the "co-owners".[5] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[6]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, "reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities." In the 2025 LTRA, Colorado is included in the WECC Rocky Mountain assessment region.

[4] U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[5] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.

[6] As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as

Order No. 202-25-14, issued pursuant to FPA section 202(c) on December 30, 2025, required that Tri-State and the co-owners take all measures necessary to ensure that Craig Unit 1 continues to be available to operate for 90 days, until March 30, 2026. This order was based on my determination that emergency conditions existed within the WECC Northwest assessment area.

Specifically, I determined that the WECC Northwest assessment area faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.[7] I determined that the continued availability of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[8] I determined that the continued availability of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.[9] My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The 2024 LTRA notes that:

> [f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.[10]

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employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[7] *See, e.g.*, *Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy,* Order No. 202-25-14, at 1–2 (Dec. 30, 2025).

[8] *See, e.g.*, *id.* at 1–3.

[9] *See, e.g.*, *id.* at 3.

[10] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024, corrected Jul. 11, 2025), at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf .

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which included Colorado at the time, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[11] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[12]

*CONTINUING EMERGENCY CONDITIONS*

The emergency conditions that necessitated the issuance of Order No. 202-25-14 continue, both in the near and long term.[13] The availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[14] While NERC assessed that the WECC Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,[15] the area has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35."[16] The LTRA also notes that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.[17] Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTOs) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.[18]

The 2025 WECC Western Assessment of Resource Adequacy notes that "the West's planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see

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[11] WECC, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA% 202024%20Peak%20Demand%20by%20Subregion.pdf.

[12] WECC, Western Assessment of Resource Adequacy, https://feature.wecc.org/wara/.

[13] Further, as noted in Order No. 202-25-14, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. *See* Order No. 202-25-14 at 1.

[14] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[15] *Id.* at 7.

[16] *Id.* at 160.

[17] *Id.* at 161.

[18] *Id.*

energy shortfalls as early as 2028."[19] The assessment goes on to say that "[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk."[20] Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources."[21]

Since 2019, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.[22] Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[23] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.[24] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[25] Additionally, Colorado Public Utilities Commissioners

[19] WECC, *Western Assessment of Resource Adequacy*, https://feature.wecc.org/2025wara/index.html.

[20] *Id.*

[21] *Id.*

[22] U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado, (last accessed Mar. 18, 2026),* https://www.eia.gov/electricity/data/browser/#/topic/0? agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[23] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Conventional Steam Coal* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

[24] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

[25] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Onshore Wind Turbine* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/.

have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.[26]

Order No. 202-25-14 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[27] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[29]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[30] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

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[26] RTO Insider, *Comanche 3 Repair Delay Raises RA Concerns in Colorado*, (March 26, 2026), https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/.

[27] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[28] *Id.*

[29] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[30] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

*ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[31] This statutory language constitutes a specific grant of authority to the Secretary to require the availability and operation of Craig Unit 1 when the Secretary has determined that such availability and operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through June 28, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. For March 31, 2026, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority,[32] or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator,[33] as applicable.

B. From April 1, 2026, SPP, Tri-State and the co-owners shall take all measures

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[31] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[32] *See* EIA-930A 2024 Data, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930A 2024 SCH 2, the balancing authority (BA) Code for Craig is WACM. *See* EIA-930 data reference tables, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930 data reference tables BA Code WACM is associated with Western Area Power Administration—Rocky Mountain Region.

[33] SPP, *Western RC Services*, https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20(RC),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project.

necessary to ensure that Craig Unit 1 is available to operate.[34] For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.

C. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A and paragraph B. SPP and Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

D. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

E. By April 14, 2026, SPP and Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

F. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

I. This Order shall be effective from March 31, 2026 through June 28, 2026, with the exception of applicable compliance obligations in paragraph E.

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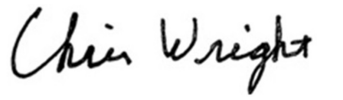
[34] WAPA, *Southwest Power Pool RTO Membership Initiative*, https://www.wapa.gov/about-wapa/the-source/key-topics/southwest-power-pool-membership/#:~:text=Since%202020%2C%20WAPA's%20Colorado%20River,FERC%20website%20under%20Docket%20No.

Issued in Washington, D.C. on this 30th day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Colorado Public Utilities Commission**
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit UU: Tri-State, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (Jan. 29, 2026)

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January 29, 2026

**Via Email**

Secretary Chris Wright
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Alex Fitzsimmons, Director
Office of Cybersecurity, Energy Security, and Emergency Response
1000 Independence Avenue, SW
Washington, DC 20585

**Re: Craig Station, Order No. 202-25-7**

Dear Secretary Wright and Mr. Fitzsimmons:

Pursuant to Section 313(a) of the Federal Power Act,[1] and Section 301(b) of the Department of Energy Organization Act,[2] Tri-State Generation and Transmission Association, Inc., and Platte River Power Authority hereby submit for filing the enclosed request for rehearing and for clarification.

Please contact me if you have any questions.

Respectfully submitted,

*/s/* Jennifer Quinn-Barabanov

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[1] 16 U.S.C. § 825*l*(a).

[2] 42 U.S.C. § 7151(b).

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| *In re Craig Order No. 202-25-14* | ) | Order No. 202-25-14 |
| | ) | |

# REQUEST FOR CLARIFICATION AND FOR REHEARING OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER POWER AUTHORITY

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Pursuant to Section 313(a) of the Federal Power Act,[1] and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),[2] and the applicable rules of practice and procedure,[3] Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) hereby file this Request for Clarification and Rehearing of the Order No. 202-25-14 dated December 30, 2025 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate. Craig Unit 1 was scheduled to shut down by December 31, 2025.[4]

## SUMMARY

Petitioners and the Department of Energy (DOE) share the goal of securing reliable and affordable electricity generation assets for their service areas' energy grid, including in the event of an energy emergency. For years, Petitioners have engaged in thorough, deliberate, and industry-leading resource planning to achieve this same end. Petitioners' resource planning ensures that the communities they serve are supported by electricity generation resources sufficient to respond to

[1] 16 U.S.C. § 825l.

[2] 18 C.F.R. § 385.713 (2024).

[3] U.S. Dep't of Energy, DOE Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214, 385.713.

[4] Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

forecasted extreme weather events and demand growth, relying on coal, gas, dual-fuel, hydropower, solar, wind, and battery assets.

Petitioners will continue to work with DOE and other government agencies to secure reliable, affordable generation portfolios, but submit this request for clarification and rehearing because keeping Craig Unit 1 available to operate will not best meet DOE's goal of securing dispatchable electricity resources in the northwestern United States. Tri-State and Platte River, as member-owned and municipal public utilities, respectively, face unique challenges from the DOE's Order that lead them to file this request. The costs of compliance fall directly on their members and customers, who must now pay to respond to the DOE's finding that utilities in the northwestern United States have "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes," DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The members and customers must pay those costs even though neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order. For example, Tri-State has numerous members in New Mexico and Nebraska. Petitioners have already paid for and planned investments in the generation resources needed to secure reliable and sufficient capacity for their systems. The Order therefore imposes additional costs to Tri-State's membership and the communities served by Platte River.

Petitioners respectfully ask DOE to reconsider the Order and to work with Petitioners to find a more effective and affordable path forward, one that will not

delay retirement of Craig Unit 1. Petitioners continue to stand ready, willing, and able to work cooperatively with DOE and any other federal agencies to address energy emergencies in a manner that minimizes costs, promotes reliability, and complies with the law.

## STATEMENT OF ISSUES

Pursuant to Section 313(a), Petitioners request clarification and, in the alternative, rehearing based upon the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical taking and a regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).

2. Because DOE predicated the Order on long-term concerns, Petitioners were deprived of the process due to them pursuant to the Administrative Procedure Act (APA) and the Federal Power Act (FPA), and the Fifth Amendment to the United States Constitution. This constitutes a violation of Petitioners' due process rights as guaranteed by the Fifth Amendment. *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991); *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970).

3. There is a disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives. DOE, therefore, did not establish that the Order "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373. It is, therefore, arbitrary and capricious.

4. The Order does not align with the statutory objectives of the Federal Power Act (FPA), because it requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, arbitrary and capricious.

## BACKGROUND

### A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,[5] Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.[6] Tri-State is wholly owned by its electric distribution cooperative and public power district members (Utility Members) and three non-Utility Members (Non-Utility Members)[7] and was formed by its Utility Members for the purpose of providing the Utility Members with wholesale power and transmission services for resale to their retail customers.

Through their participation in the cooperative, the Utility Members serve retail customers across Wyoming, Nebraska, New Mexico, and Colorado. Some, but not all, of the Utility Members and their retail customers are located in the 2024 Western Electricity Coordinating Council (WECC) Northwest region.[8] The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include suburban and rural residences, farms and ranches,

[5] COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

[6] *Tri-State Generation and Transmission Ass'n*, 170 FERC ¶ 61,221, at P 37 (2020).

[7] Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

[8] The boundaries of this region changed from 2024 to 2025, *see* note 24, *infra*.

and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities within the Western Area Power Administration's (WAPA) Western Area Colorado Missouri (WACM) balancing authority area, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities are included in the Western Power Pool reserve sharing pool. This pool facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State expects to participate in the Southwest Power Pool's (SPP) regional transmission organization, with respect to Tri-State's service in the WACM balancing authority area within the Western Interconnection, beginning in April 2026.

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C.

§ 824(f). Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is headquartered in Fort Collins, Colorado. At Platte River's main generating facility, Rawhide Energy Station, Platte River has one coal-fired power plant, Unit 1, with a nameplate capacity of 280 megawatts (MW), as well as five natural gas-fired units with a total capacity of 388 MW. Platte River also purchases 297 MW of wind energy and 202 MW of solar energy through long-term power purchase agreements and is a preference customer of WAPA's Colorado River Storage Project and Loveland Area Projects, providing up to 78 MW of hydropower. Platte River is a partial owner of two additional coal-fired units, Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River plans to participate in SPP's regional transmission organization beginning in April 2026.

### B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates

Craig Unit 3. Together, these units are transmission-interconnected to the broader power grid and supply electricity into Western energy markets.

As part of its resource plan to address the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to curtail output from Axial Basin when all facilities are generating at or near full output due to limited transmission capacity.

As a result of changed market conditions and state and federal requirements, Unit 1 has been scheduled for retirement since 2016, and Units 2 and 3 have been scheduled for retirement since 2020, beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. A retirement date for each Craig unit is now specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits.[9] In 2016, Craig Unit 1's retirement date was adopted into what was then Colorado Air Quality Control Commission Regulation No. 3 on Stationary Source Permitting and Air Pollutant Emission Notice Requirements and the Regional Haze State Implementation Plan, the latter of which was approved by EPA in 2018.[10]

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[9] COLO. CODE REGS. 1001-27.

[10] *See Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan*, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine plans to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand of the Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand of the Craig Unit 2 through its planned retirement date.

### C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has averaged $12.99 million annually.[11] By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners.

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Control Div., *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016), https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135.

[11] Over the last ten years, the operations and maintenance cost to run Tri-State's share of Craig Unit 1 has averaged $23.9 million annually (inclusive of coal cost and depreciation expense). Over the last ten years, the fixed operations and maintenance cost to run Platte River's share of Craig Unit 1 has averaged roughly $2.3 million (exclusive of coal cost and depreciation expense) annually.

Operation and maintenance of Craig Unit 1 has been undertaken prudently to reflect the scheduled 2025 retirement. The Craig Unit 1 owners have deferred optional maintenance since 2019. Craig Unit 1 has had multiple breakdowns and required significant repairs to continue operating into 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs made in direct response to the Order.[12]

### D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14. The Order declared that "an emergency exists within the WECC-NW assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The Order predicated its emergency on (1) "increasing demand" and (2) "shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years." DOE stated, "[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety." *Id.* at 3.

DOE predicated energy reliability concerns on the 2024 Long-Term Reliability Assessment (2024 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-NW assessment area, "which includes Colorado, Idaho,

[12] Tri-State Generation & Transmission Ass'n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

Montana, Oregon, Utah, Washington, and Wyoming[.]" *Id.* at 1. DOE also pointed to the 2024 WECC Western Assessment of Resource Adequacy. The concerns included (1) greater "energy variability" due to the region's use of wind and hydropower; (2) planned retirement of baseload generation facilities fueled by coal, natural gas and nuclear; and (3) projected regional load growth. *Id.* at 2.[13]

The Order required Tri-State and the other co-owners of Craig Unit 1 to:

1. Take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable;
2. Limit operation of Craig Unit 1 to the times and within certain parameters to minimize adverse environmental impacts;
3. Provide daily notification to DOE reporting whether Craig Unit 1 has operated in compliance with the Order;
4. Comply with applicable environmental requirements including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions;
5. Update DOE on measures taken or planned to ensure operational availability of Craig Unit 1 by January 20, 2026; and
6. File with the FERC Tariff revisions or waivers to effectuate the Order with rate recovery available pursuant to 16 U.S.C. § 824a(c).

Tri-State has already taken and will continue to take steps to comply with the Order. In coordination with the other co-owners of Unit 1, it timely submitted its

[13] The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

update to DOE on January 20, 2026, describing the measures it has taken and plans to take to ensure operational availability of Craig Unit 1. Tri-State has submitted and continues to submit daily notification to DOE pursuant to the Order.

## ARGUMENT

Petitioners seek rehearing and clarification on two fronts. *First*, the Order, as drafted, effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet Section 202(c)'s requirement for a reasoned finding that compels operation of Craig Unit 1 as the "best" solution to the identified emergency.

### I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 largely because of the uneconomic nature of the facility, and Petitioners have taken numerous steps over the years to prepare for its closure. By mandating that Tri-State continue operating the facility on a sustained basis for months beyond its planned closure date, and thus directing its operations in a manner entirely inconsistent with Petitioners' own planned retirement of the facility, the Order effects an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the physical infrastructure of the facility and mandated a variety of changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

A taking is not prohibited so long as it provides just compensation, but this taking comes with no assured government compensation. FERC cost recovery shifts costs onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be complex procedurally and substantively and could leave material costs unrecovered from the Order's putative beneficiaries. The Order gives Petitioners no constitutionally adequate avenue for just compensation.

### A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. "When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation." *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take a variety of forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, "[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking." *Ark. Game & Fish Comm'n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to a property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings in "as complete a sense as if the Government held full title and ownership." *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis,[14] and in clear departure from Petitioners' own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings that must be compensated. *Second*, even if not characterized as a government seizure of operations, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment, requiring staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1 as the facility's operations deplete limited fuel reserves that were allocated to other units that remain operational and are needed for reliability—the depletion of these stockpiled reserves will require Petitioners to obtain replacement coal at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1's operations could further impede Tri-State's use of the nearby Axial Basin generating facility by constraining Tri-State's ability to inject power from that facility onto the grid.

[14] Petitioners note that other similar Section 202(c) orders, issued to other utilities and on similar grounds, have been repeatedly renewed. *See, e.g.*, DOE Order No. 202-25-3 (May 23, 2025), *renewed for 90 days by* DOE Order No. 202-25-7 (Aug. 20, 2025), *renewed for 90 days by* DOE Order No. 202-25-9 (Nov. 18, 2025). Petitioners are reasonably concerned that DOE Order No. 202-25-14 could be similarly repeatedly renewed.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,[15] making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see*, *e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (holding that a government seizure of part of a leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; and (2) limit operation of Craig Unit 1 to

[15] Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) (hereinafter "Rolsma (2024)").

certain times and parameters to minimize adverse environmental impacts. Even the narrowest version of the measures necessary to ensure that Craig Unit 1 is available to operate include extensive repairs to Craig Unit 1's physical facility and the ongoing employment of some share of approximately 130 staff to maintain the Craig facility, operate equipment, and remain ready to operate. The Order requires Petitioners to take these significant steps, unnecessary but-for the Order, for a prolonged period of time. This closely resembles the sustained mandate to operate that the *Pewee Coal* Court held was a taking.[16]

Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067 (describing how the "unconsented closure" of a coal-fired power station constituted a *per se* taking of the facility owner's property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne*, 576 U.S. 351).

By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to the government's instructions and mandating an

[16] The *Pewee Coal* Court did not enjoin the government's actions—the wartime emergency justified the government's effort to keep coal mines operational. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is "entitled to the benefits and subject to the liabilities" of operating a facility it takes over).

unconsented re-opening of a non-operational facility—for not hours or days but months—DOE engages in a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, mandating that Petitioners make Craig Unit 1 ready for operations compels Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused. *Second*, operations require fuel, which compels Petitioners to deplete the Craig facility's limited fuel reserves intended for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender and exhaust coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. And *third*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating could constrain the ability of these resources to fully access the grid.

a. Physical Changes to Craig Unit 1

Bringing Craig Unit 1 back into service has already required modifications to the physical infrastructure on the site, beginning with repairs to Craig Unit 1's failed

Main Steam Stop Valves #1 and #2, and including additional maintenance to the unit's baghouse that had previously been deferred based on the unit's planned December 31, 2025 retirement. Petitioners must also perform emissions testing and other evaluations to ensure that Craig Unit 1 complies with applicable environmental requirements to the "maximum extent feasible while operating consistent with the emergency conditions." Order No. 202-25-14 at 4. Ongoing operations at the site will also require continual maintenance and staffing readiness, with the potential for further equipment failures that require repair and staffing (including overtime). And long before Craig Unit 1 was scheduled to retire, Petitioners both engaged in careful resource planning resulting in generation portfolios for the future that meet all member/customer needs, as well as planning reserve margins necessary to ensure reliable capacity in the event of extreme weather events and other emergencies, all based on the assumption that Craig Unit 1 would retire from service on December 31, 2025.

Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (citing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds, Cumbre Inc. v. State Compensation*

*Ins. Fund*, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to make significant repairs to a facility they had planned to imminently retire for good. This is the kind of taking described in *Furey*.

### b. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.[17] Before closing the Colowyo Mine, Tri-State stockpiled sufficient reserves to operate its share of the Craig Units until their respective retirements. The only practical source of fuel for Craig Unit 1 to maintain readiness after its planned retirement, and to make use of in the event of a dispatch, are Craig Units 2 and/or 3's previously acquired and allocated reserves.[18]

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public reliability objective. Under *Horne*'s reasoning, forced depletion of a

[17] Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

[18] The diversion of this coal will necessitate future purchases of replacement fuel at uncertain cost, thereby imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Tri-State to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies.

utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

#### c. Axial Basin

The 145 MW Axial Basin generating facility is in the same general location as the Craig Generating Station and relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure, a clear physical intrusion. This transmission limitation could lead to further physical intrusion by potentially forcing the curtailment of one or more of the other generation facilities to ensure that there was sufficient transmission capacity available for Unit 1 to comply with the Order.

### B. DOE's Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point Nursery*, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986 (1984) (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 124 (1982), which evaluates regulatory takings based on: (1) the regulation's economic

impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action.

The Order constitutes a regulatory taking under this analysis. The Order levies substantial economic impacts on Petitioners through both direct maintenance costs and the disruption to Petitioners' planning with associated downstream costs. The Order also disrupts Petitioners' reasonable investment-backed expectations rooted in years-long resource and economic planning, and interferes with Petitioners' operations and their contractual and regulatory rights.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. As discussed above, Petitioners will necessarily incur a variety of operations and maintenance costs to ensure that Craig Unit 1 is ready and able to operate on request, with no economic benefit available from retaining the to-be-retired facility because it is uneconomic to operate.

Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1, while the other Craig Units are operating, can impede Tri-State's ability to dispatch its nearby Axial Basin generating facility. This in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible value). *See Ruckelshaus*, 467 U.S. at 1011 (trade secrets are property); *Cienega Gardens v. United States*, 331 F.3d 1319, 1329 (Fed. Cir. 2003) (option rights to prepay subsidized mortgage and exit affordable-housing program are property); *Casitas*

*Mun. Water Dist. v. United States*, 543 F.3d 1276, 1288–96 (Fed. Cir. 2008) (water capacity rights are property). Forced operations would prevent Petitioners from most efficiently and affordably managing the transmission and generation system.

2. Investment-Backed Expectations

"The regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed] expectations." *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O'Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner's choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners' reasonable investment-backed expectations on several fronts. DOE's use of Section 202(c) authority to address long-term predicted shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.[19] The Order fundamentally alters DOE's longstanding approach in a novel, untested way that could not be predicted from DOE's actions until recently, a decade after Craig Unit 1's 2025 retirement was announced. Petitioners could not have fairly anticipated DOE's novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners' reasonable expectations.

[19] *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

Moreover, diverting coal from Craig Unit 1 to comply with the Order depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations. The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws,[20] disruption to these longstanding relationships disturbs Petitioners' ability to manage risk, engage in long-term planning, and maintain their reputations as reliable counterparties. Notwithstanding possible regulatory action, Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their investment-backed expectations.

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since. As is best practice, Petitioners engaged in extensive long-term planning with both government and private-sector partners, and Petitioners' plan to close Craig Unit 1 is part of a long-term plan to retire Unit 1 for economic reasons. Disruption of these long-term plans through a shorter-term Order upsets Petitioners' reasonable investment-backed expectations.

[20] Section 202(c)(3) does not define "environmental law" in this context and the scope of that term is untested.

3. Character of the Taking

The character of a governmental action is defined by "the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant's prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented." *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). "A 'taking' may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good." *Penn Central*, 438 U.S. at 124 (citations omitted).

The character of the Order's action further strengthens the case for a regulatory taking. As discussed in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. Whether compensation is "just" is measured by relation "both to an owner whose property is taken and to the public that must pay the bill[.]" *United States v. Commodities Trading Corp.*, 339

U.S. 121, 123 (1950). "The owner's loss is measured by the extent to which governmental action has deprived him of an interest in property." *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987).

There is no established process by which Petitioners will obtain government compensation for losses relating to the Order. Section 202(c) and its implementing regulations, namely 10 C.F.R. 205.376, suggest recovery through FERC rate-making processes, but nowhere does the Order guarantee Petitioners' complete recovery.[21] As one example of the complexity of this undertaking, WAPA and the Bonneville Power Administration, as Federal Power Marketing Administrations located within WECC-NW, are exempt from most FERC jurisdiction.[22] It is not immediately clear how the FERC rate-making process could be used to secure cost recovery from utilities serving areas located within the scope of the emergency but over which FERC lacks jurisdiction.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. The duty to pay compensation for a taking runs to the government—"a takings claim requires just compensation from the government, not from a private third party." *See*

[21] Additionally, the terms of the Order could have substantive impact on Tri-State's ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g.*, *Tri-State Generation and Transmission Ass'n,* 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

[22] Stating that "[n]o provision in this subchapter shall apply to, or be deemed to include, the United States." 16 U.S.C. § 824(f) (2024).

*Deutsche Bank Nat'l Trust Co. v. SFR Invests. Pool 1, LLC*, Case No. 2:14-cv-001131-APG-VCF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016); *see also Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations). This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery. DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

## II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional frailties. While Petitioners share DOE's goal of ensuring that the Northwestern United States has reliable and affordable electricity, the Order misses the mark.

*First*, the Order violates Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. While emergencies sometimes allow the government to provide only post-deprivation process, the government must do more than reference the word "emergency"—rather, it must show that the *kind* of emergency that requires such fast-moving action has occurred. The Order's asserted

emergency is no such emergency. And the Order disrupts a considered resource planning effort.

*Second*, the Order does not meet the requirements of Section 202(c). It does not consider reasonable alternatives as required by Section 202(c), including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings including from objective, industry-leading forecasting methods. *Third*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.[23]

A more deliberative process would, on the whole, work better to address DOE's concerns about the reliability of the electrical grid in the northwestern United States, and, in particular, the Mountain West. Petitioners stand ready to work with DOE to make their service area as reliable as possible and best serve their members and customers, doing so in a manner that is economically efficient.

### A. The Order Violates Petitioners' Constitutional Due Process Rights and Disrupts Carefully Considered Reliability Planning

The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due

[23] As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although Petitioners take the position that the Order does not comply with the requirements of Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking even if the Order is determined to be unlawful. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

process of law." U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, & 824p.

Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as an emergency tool meant to address fast-moving and unexpected situations. *Indus. Park Dev. Co. v. EPA*, 604 F. Supp. 1136, 1142 (E.D. Pa. 1985) ("[A]dministrative deprivation of [a] property interest violates the Constitution's due process guarantees except in very narrowly circumscribed emergency situations."). However, "[t]here is a relation between the kind of emergency and nature of the solution." *Pa. Gas & Water Co.*, 427 F.2d at 577. Where, as here, the declared emergency does not involve immediate and concrete concerns (potentially in 2029 if new generation is not built as planned), a hearing is certainly feasible, and, absent a hearing, Petitioners are deprived of their right to due process. *See Indus. Park Dev. Co.*, 604 F. Supp. at 1145 (holding that "[u]nilateral administrative action . . . should be saved for cases of extreme emergency"); *Miller*,

945 F.2d at 353 (emergency insufficient to avoid need for pre-deprivation hearing, but concluding that sufficient hearing had occurred).

The Order's emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event, such as unusually extreme weather or another plant's sudden unplanned outage. Rather, the emergency articulated by the Order is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC Northwest assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Formal notice to the co-owners, moreover, was lacking. The Order's imprecision on boundaries of the region at issue,[24] not only highlights the lack of immediate crisis, but also fails to give Petitioners proper notice of the precise contours of the emergency. Petitioners were, therefore, deprived of their constitutional right to notice and a hearing before the Order came into effect.

The effect of this deprivation is significant. Petitioners have carefully planned the retirement of the Craig facility—including Craig Units 2 and 3's reliance on

[24] The Order relies on NERC's 2024 LTRA, which discusses conditions throughout the sweeping and populous WECC Northwest assessment area—an area that includes "Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota[.]" *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 127 (corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf. However, NERC's more recent and more targeted 2025–2026 Winter Reliability Assessment from November 2025 shows that the new WECC-Rocky Mountain region—redrawn to better reflect local conditions than the vast and heterogeneous old WECC-Northwest region—has more than enough power to meet immediate winter needs. *See* N. Am. Elec. Reliability Corp., 2025 Winter Reliability Assessment (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. Craig Unit 1 and most of Petitioners' service territory is located in the WECC-Rocky Mountain region.

stockpiled coal. Petitioners have also planned and invested to bring new generation online, such as the Axial Basin facility, to ensure reliability even as Craig Unit 1 is carefully retired. If the Order proceeds and Unit 1 runs, it deprives the other units of fuel. This undermines Petitioners' planning, imposes "reliability" costs on Tri-State's members and Platte River's ratepayers a second time, and disrupts the operation and economics of the other coal resources still operating. A more deliberative process with the required pre-deprivation hearing would have allowed Petitioners to work with DOE to address concerns about reliability and shape a more workable plan.

### B. The Order Failed to Consider Reasonable Alternatives

DOE could have taken other steps to more effectively meet the energy emergency identified in the Order. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2029 time-horizon of the asserted emergency. This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue. *Pa. Gas & Water Co.* 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such

alternatives.") (citation and footnote omitted). The Order reflects no consideration of alternatives, let alone a case for mandating Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious.

Compelling Craig Unit 1 to remain available to operate after its planned retirement date must be the "best" measure to address this long-term reliability concern across the region described in the Order. "[R]easonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions." *Michigan v. EPA*, 576 U.S. 743, 753 (2015). This weighing process requires engagement with the factual record, as reflected in DOE regulations, which require applicants to provide extensive information related to operations and alternative courses of action.[25] These requirements reflect the understanding that Section 202(c) should only be used where unit-specific alternatives have been considered, applied, and deemed inadequate based on the facts on the ground. The record in this proceeding reflects that neither these facts nor any reasonable alternatives were considered in connection with the Order.

DOE's need to consider alternatives, based on a clear factual record, is particularly important given Craig Unit 1's status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance, and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives.

[25] *See* 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other 'entities' that may be directly affected by the requested order." 10 C.F.R. § 205.373(g)–(i).

Further, the Order fails to consider how mandating Craig Unit 1's continued operation interferes with Petitioners' ability to invest in other generation capacity and therefore undermines the very ends that it purports to advance. For instance, the Axial Basin generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; if all three Craig units are operating, Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

A lawful exercise of the emergency powers contained in Section 202(c) required consideration of reasonable regulatory alternatives. For example, the Order does not explain why DOE or FERC could not proceed through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process. Proceeding with a notice of proposed rulemaking for consideration and final action would have minimal short-term risks and is appropriate to the timeline of the described emergency, which, by DOE's supporting evidence, is predicted to occur no earlier than "in Summer 2029 onward" (because "the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed").[26] Similarly, DOE could have evaluated whether it had authority to take proactive action to insure that "new resources" in the region are not "significantly delayed."

[26] N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 128 (corrected July, 11 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

In the absence of such consideration, and the disclosure of the relevant rationale, Petitioners and the public "cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]" *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1's continued operation was selected as the "best" solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it was contrary to law and an arbitrary and capricious exercise of agency authority.

### C. The Order is Inconsistent with the FPA's Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is "inconsistent with the statutory mandate" or "frustrate[s] the policy that Congress sought to implement." *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance a variety of policy goals, including protecting consumers from "excessive rates and charges," *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted)); "maintaining competition to the maximum extent possible[,]" *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the "orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).[27]

[27] "Recognizing the careful balance that the FPA strikes between federal and state regulation" FERC recently found that "states retain exclusive authority over . . . the generation mix." *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (Dec. 18, 2025). Long-term economic and planning decisions regarding Tri-State's resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. *See Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Resources, LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) ("[FERC] may regulate the transmission, but not the generation, of electricity[.]").

The Order, by compelling an uneconomic unit to remain operational on the eve of its retirement, upends Petitioners' ability to plan their systems in an orderly fashion and to act with confidence in a competitive marketplace. Because the Order is at odds with the statutory objectives of the FPA, it is arbitrary and capricious.

## CONCLUSION

Tri-State is a not-for-profit, member-owned cooperative and Platte River is a not-for-profit municipally owned joint action agency. Both utilities aim to work with government at all levels to best serve the communities to which they provide reliable and affordable energy. In that light, Tri-State has taken the steps necessary to plan for a reliable system that would have a planning reserve margin of at least 22% even with the retirement of Craig Unit 1, for which its Utility Members have paid. Platte River has likewise proactively developed resources that more than replace Craig Unit 1's energy and capacity to reliably serve its owner communities and meet the planning reserve margins SPP requires for its expanded western footprint (19% for summer; 40% for winter), and for which its owner communities have already paid.

The Order effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirement that DOE's chosen policy rationally "best address[es]" the stated emergency. Requiring Petitioners—not all of whom are located in the WECC Northwest region described by the Order—to suffer additional costs *and* uncertainty because of potential conditions created by utilities outside Petitioners' service area, is fundamentally unfair and harms affordability. Petitioners urge DOE to reconsider the Order.

Respectfully submitted,

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## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of January 2026.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit VV: CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E

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**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**

| | | |
|---|---|---|
| **2026 ELECTRIC RESOURCE ADEQUACY ANNUAL REPORTS** | ) ) ) ) ) | **PROCEEDING NO. 26M-0028E** |

**TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S NOTICE OF 2026 RESOURCE ADEQUACY ANNUAL REPORT**

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), pursuant to §40-43-104(1)(a), C.R.S., respectfully submits this Notice of 2026 Resource Adequacy ("RA") Annual Report informational filing.

## I. BACKGROUND

On or before April 1, 2026, Tri-State, as a load serving entity ("LSE"), is required under §40-43-104(1)(a), C.R.S., to provide the Colorado Public Utilities Commission ("Commission") a RA Annual Report identifying the generating resources and accredited capacity used to serve its Utility Members.[1] On January 1, 2026, the Commission opened Proceeding No. 26M-0028E to receive these reports.

## II. TRI-STATE'S 2026 RA REPORT

Tri-State has complied with this requirement with Figure 1 and Table 1.[2] Tri-State's 2025 RA Annual Report has also been made available on Tri-State's website, here: https://tristate.coop/resource-planning.[3]

[1] The Colorado Resource Adequacy Act of 2023 became effective August 7, 2023 (House Bill 23-1039).
[2] Colorado Energy Office ("CEO") has requested that entities subject to §40-43-104, C.R.S. also complete a "Resource Adequacy Spreadsheet" to be returned to CEO by April 30, 2026. Tri-State intends to voluntarily respond to this request.
[3] On January 11, 2025, Tri-State received guidance from CEO (pursuant to §40-43-104(3), C.R.S.) requiring each LSE to make its RA annual report available on its website and searchable by including "Resource_Adequacy_2026."



Colorado PUC E-Filings System

FIGURE 1 –LOAD AND RESOURCES

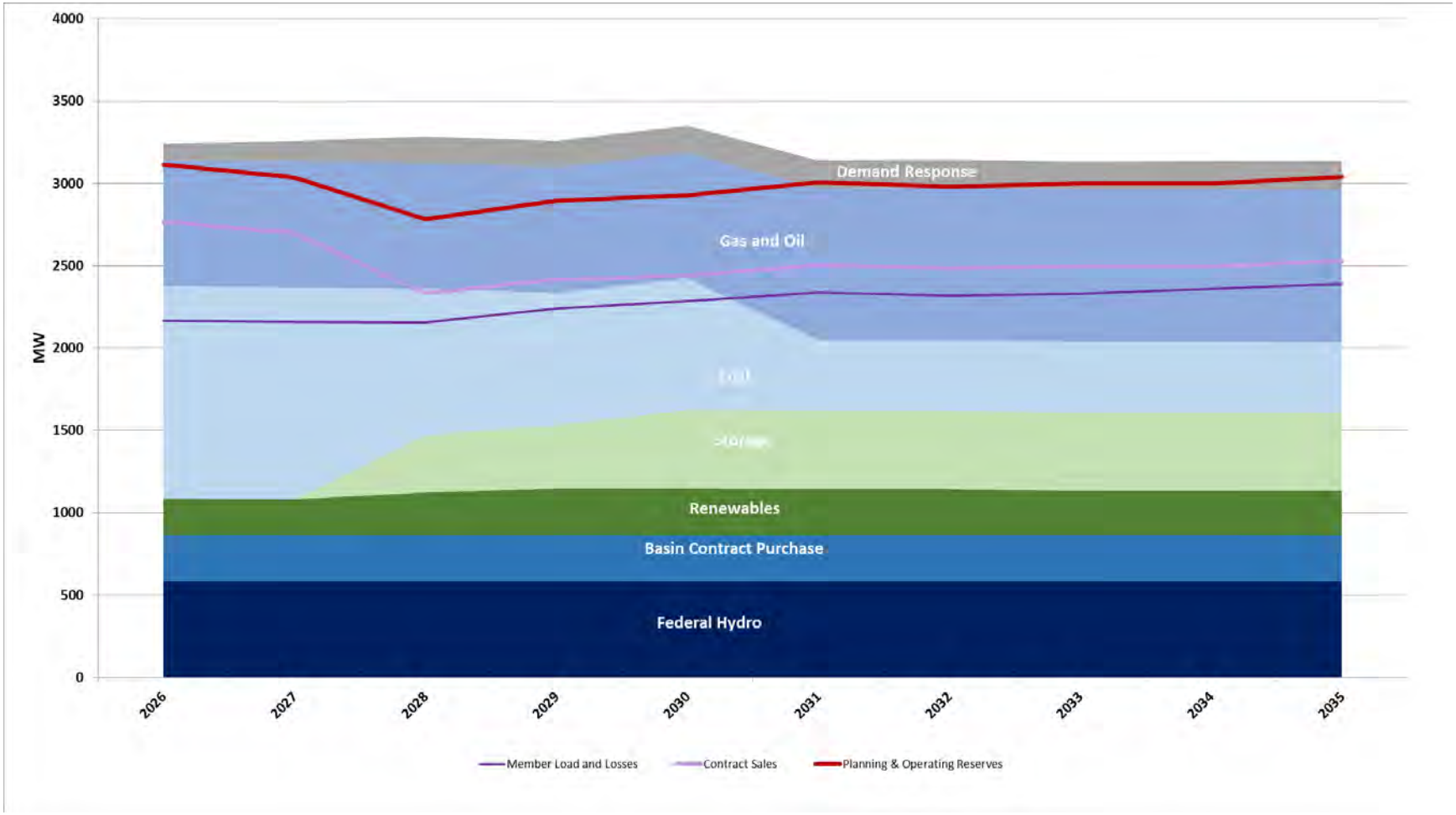

TABLE 1 – LOAD AND RESOURCES

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Federal Hydro | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 | 584 |
| Contract Purchases | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 |
| Renewables[4] | 226 | 222 | 260 | 286 | 286 | 281 | 281 | 272 | 273 | 271 |
| Demand Response | 100 | 124 | 161 | 162 | 164 | 165 | 167 | 169 | 170 | 172 |
| Coal Generation[5] | 1287 | 1286 | 888 | 800 | 800 | 431 | 432 | 431 | 432 | 431 |
| Gas & Oil Generation[6] | 765 | 765 | 765 | 765 | 765 | 925 | 925 | 925 | 925 | 925 |
| Storage[7] | 0 | 0 | 349 | 383 | 474 | 474 | 474 | 474 | 474 | 474 |
| *Total Resources* | 3239 | 3257 | 3285 | 3259 | 3351 | 3138 | 3141 | 3132 | 3136 | 3135 |
| Member Load and Losses[8] | 2166 | 2160 | 2156 | 2241 | 2284 | 2337 | 2317 | 2332 | 2358 | 2390 |
| Planning & Operating Reserves | 348 | 341 | 451 | 476 | 489 | 505 | 498 | 502 | 502 | 511 |
| Contract Sales | 601 | 537 | 177 | 177 | 155 | 166 | 166 | 166 | 139 | 139 |
| *Total Obligations* | *2001* | *1971* | *1781* | *1865* | *1906* | *1957* | *1936* | *1949* | *1948* | *1978* |
| **Excess Resources** | **123** | **219** | **501** | **364** | **422** | **131** | **160** | **133** | **136** | **95** |

[4] Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.
[5] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[6] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[7] Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.
[8] Western Interconnection Load.

Tri-State's report covers its Utility Members as LSEs, for the portion of their loads served by Tri-State,[9] pursuant to §40-43-104(2), C.R.S.

In accordance with §40-43-104(1)(c), C.R.S., Tri-State understands that the Colorado Energy Office will, by July 1, 2026, utilize Tri-State's report and that of other LSEs to create an aggregated statewide report.

Submitted this 17th day of March, 2026.

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[9] Tri-State expects that certain Utility Members that are exiting Tri-State membership may supply separate RA Annual Reports, to the extent applicable.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| | | |
|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit WW: NERC, Long-Term Reliability Assessment (Jan. 2026)

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Long-Term Reliability Assessment

## January 2026



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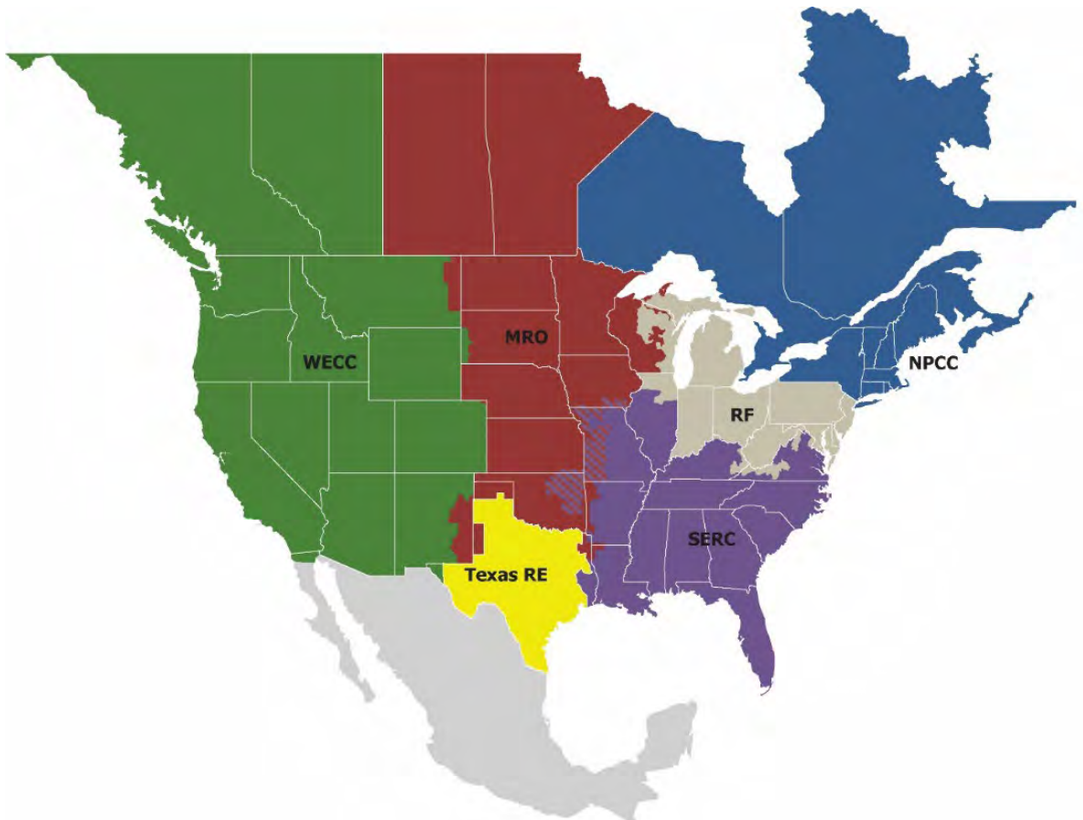
# Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.




| | |
|---|---|
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | WECC |

# About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

The *Long-Term Reliability Assessment* (LTRA), along with NERC's other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The *Summer Reliability Assessment* (SRA) and *Winter Reliability Assessment* (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- ***State of Reliability* Report (SOR):** The SOR contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.
- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the ERO Event Analysis Program. This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC's website.

## Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

## Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

## Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

## Reading This Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[5] ERO Reliability Assessment Process Document

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

# Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the *2025 LTRA*, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

## Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.[7] Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.[8] **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in **Figure 1** and described in **Table 1**.

[7] In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the **Capacity and Energy Risk Assessment**.

[8] The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See **Risk Categories** in this report for a complete description.

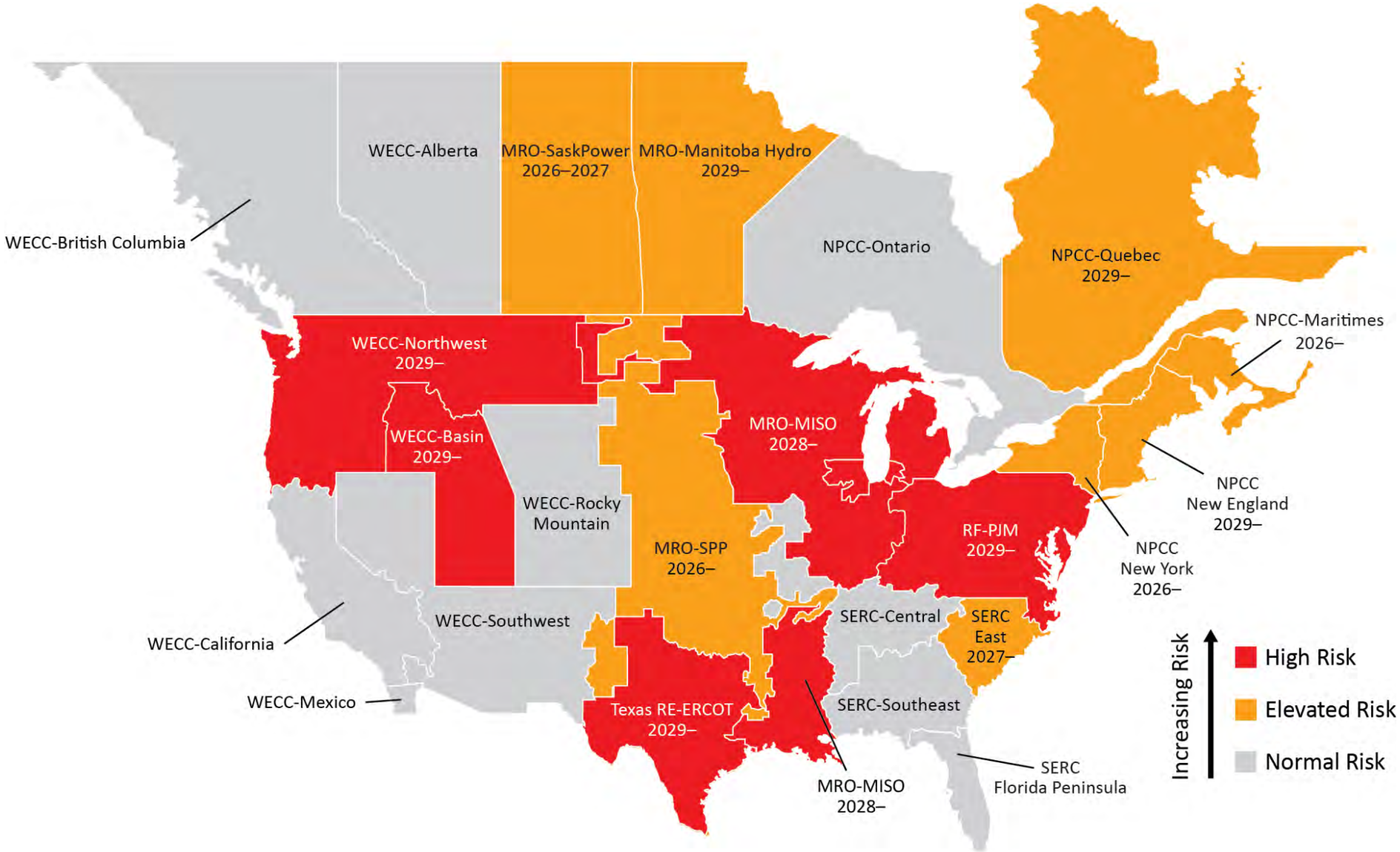



**Figure 1: Risk Area Summary 2026–2030**

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

**Table 1: Capacity and Energy Risk Assessment Area Summary**

| Assessment Area | Risk Level (High, Elevated, or Normal) | | | | | Risk Summary |
|---|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 | |
| MISO | | | | | | Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved *Expedited Resource Addition Study* (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the *2025 LTRA*. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics. |
| MRO-Manitoba | | | | | | With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions. |
| MRO-SaskPower | | | | | | With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy. |
| MRO-Southwest Power Pool (SPP) | | | | | | Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP's *Expedited Resource Adequacy Study* is attracting additional resources. |
| NPCC-Maritimes | | | | | | Demand growth forecasts have increased since the *2024 LTRA*, while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold. |
| NPCC-New England | | | | | | Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions. |
| NPCC-New York | | | | | | Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO *2025 Q3 Star Report*. |
| NPCC-Québec | | | | | | Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season. |
| PJM | | | | | | Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis. |
| SERC-East | | | | | | Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy. |
| Texas RE-ERCOT | | | | | | Probabilistic unserved energy metrics for 2026–2027 have improved since the *2024 LTRA*, but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs. |
| WECC-Basin | | | | | | Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer. |
| WECC-Northwest | | | | | | Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter. |

### Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

### Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The **Capacity and Energy Risk Assessment** and **Regional Assessments Dashboards** sections provide details on these examples and initiatives in other assessment areas.

## Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

### Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

### Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the *2024 LTRA* by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year's LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

### Transmission Development and Interregional Transfer Capability

Transmission projections reported for the *2025 LTRA* reflect an increase in transmission development, continuing a trend that emerged in the *2024 LTRA*. This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[9] including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate ***Interregional Transfer Capability Study (Canadian Analysis)***. About 4% of transmission projects reported for the *2025 LTRA* are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the *2024 LTRA*.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

## Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

[9] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC's Large Loads Action Plan[10] and collaborate through NERC's Large Loads Task Force.[11] ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the *2026 LTRA* and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.

4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[12] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary.**

[10] NERC's Large Loads Action Plan: https://www.nerc.com/initiatives/large-loads-action-plan
[11] NERC's Large Loads Task Force webpage: Large Loads Task Force (LLTF)
[12] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

# Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such considerations have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC's LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

## Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

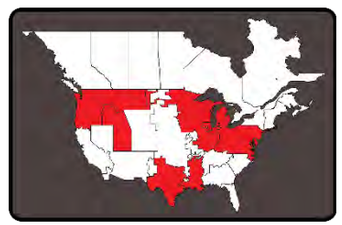
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The **Demand Assumptions and Resource Categories** section provides further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

## Risk Categories

For the *2025 LTRA*, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.



An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[13] High risk areas are those where today's demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.

For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

[13] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Resource adequacy target(s) established by regulatory authority or system operator are not met.

**Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.**



An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load



An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme[14] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

**Application of the Risk Criteria:** NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year's LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, *Evolving Planning Criteria for a Sustainable Power Grid*, alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas' risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

[14] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

| Table 2: Capacity and Energy Risk Assessment Numerical Summary | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | NEUE (ppm) | | LOLH (hours/year) | | Anticipated Reserve Margin | | | | | Reference Margin Level[15] | | | | |
| **Summer-Peaking Areas** | **2027** | **2029** | **2027** | **2029** | **2026** | **2027** | **2028** | **2029** | **2030** | **2026** | **2027** | **2028** | **2029** | **2030** |
| MISO | 1.13 | **42.39** | **0.23** | **6.61** | 11.0% | 11.2% | 9.5% | 8.6% | **4.3%** | 8.1% | 8.3% | 8.5% | 8.5% | 8.5% |
| MRO-SPP | 0.00 | 0.00 | 0.00 | 0.00 | 32.4% | 30.3% | 28.4% | 25.1% | 22.6% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% |
| NPCC-New England | 0.00 | 0.02 | 0.00 | 0.00 | 18.3% | 21.7% | 24.8% | 23.7% | 23.6% | 13.4% | 13.0% | 13.0% | 13.0% | 13.0% |
| NPCC-New York | 0.00 | 0.08 | 0.00 | 0.03 | 22.3% | 24.5% | 24.5% | 23.6% | 22.5% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| NPCC-Ontario | 0.00 | 0.00 | 0.00 | 0.00 | 29.6% | 19.8% | 28.1% | 18.7% | 19.7% | 16.1% | 19.0% | 22.6% | 15.8% | 19.5% |
| PJM | **3.50** | **65.50** | **0.61** | **9.97** | 29.7% | 28.3% | 24.3% | **18.9%** | **13.9%** | 18.6% | 20.1% | 21.9% | 23.9% | 26.3% |
| SERC-Central | 0.00 | 0.00 | 0.00 | 0.00 | 19.1% | 20.8% | 19.7% | 18.5% | 16.5% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-East | 0.98 | **2.27** | **0.15** | **0.33** | 30.6% | 30.5% | 30.5% | 31.5% | 34.9% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-Florida Peninsula | 0.00 | 0.00 | 0.00 | 0.00 | 27.4% | 25.2% | 24.3% | 22.6% | 21.1% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-Southeast | 0.00 | 0.00 | 0.00 | 0.00 | 35.9% | 29.5% | 29.8% | 24.9% | 20.9% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| Texas RE-ERCOT | **8.70** | **18.84** | **0.95** | **3.64** | 28.2% | 30.5% | 31.8% | 30.8% | 29.9% | 13.8% | 13.8% | 13.8% | 13.8% | 13.8% |
| WECC-Basin | 0.04 | **2,250** | **3.00** | **310.00** | 36.3% | 37.9% | 27.4% | 19.7% | 15.2% | 13.5% | 14.0% | 13.6% | 12.4% | 12.3% |
| WECC-California | 0.00 | 0.00 | 0.00 | 0.00 | 53.2% | 47.0% | 46.1% | 45.6% | 42.7% | 20.3% | 19.2% | 19.3% | 19.7% | 19.3% |
| WECC-Mexico | 0.00 | 0.00 | 0.00 | 0.00 | 14.9% | 13.8% | 29.9% | 27.0% | 24.6% | 7.8% | 8.0% | 9.1% | 7.2% | 7.0% |
| WECC-Rocky Mountain | 0.00 | 0.00 | 0.00 | 0.00 | 51.3% | 60.0% | 53.2% | 38.1% | 30.5% | 17.8% | 17.0% | 16.2% | 16.1% | 15.7% |
| WECC-Southwest | 0.00 | 0.00 | 0.00 | 0.00 | 41.1% | 39.6% | 38.6% | 38.4% | 36.1% | 13.3% | 13.7% | 13.6% | 12.6% | 12.2% |
| **Winter-Peaking Areas** | **2027** | **2029** | **2027** | **2029** | **2026–2027** | **2027–2028** | **2028–2029** | **2029–2030** | **2030–2031** | **2026–2027** | **2027–2028** | **2028–2029** | **2029–2030** | **2030–2031** |
| MRO-Manitoba Hydro | 0.12 | 0.23 | 0.03 | 0.06 | 13.9% | 16.7% | 15.4% | 13.6% | **1.2%** | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| MRO-SaskPower | **5.24** | 0.19 | **1.09** | 0.05 | 25.9% | 35.0% | 33.4% | 32.3% | 31.2% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| NPCC-Maritimes | 0.52 | 0.25 | **0.25** | 0.10 | **17.2%** | **18.5%** | 25.6% | 23.0% | 21.7% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% |
| NPCC-Québec | 0.00 | 0.29 | 0.00 | **0.11** | 15.6% | 16.7% | 14.7% | 13.0% | **11.5%** | 11.9% | 12.2% | 12.2% | 12.2% | 12.2% |
| WECC-Alberta | 0.00 | 0.00 | 0.00 | 0.00 | 36.2% | 45.3% | 40.7% | 38.0% | 33.0% | 11.8% | 17.6% | 14.3% | 15.6% | 11.6% |
| WECC-British Columbia | 0.00 | 0.00 | 0.00 | 0.00 | 23.4% | 19.1% | 19.5% | 24.1% | 24.2% | 11.7% | 12.1% | 12.1% | 11.6% | 11.6% |
| WECC-Northwest | 0.00 | **36.64** | 0.00 | **85.00** | 30.2% | 29.3% | 23.3% | 19.1% | 15.7% | 17.8% | 17.4% | 16.1% | 15.8% | 15.5% |

[15] Refer to the Regional Assessments Dashboards and the Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area table.

## High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

### *MISO (Normal Risk 2026| Elevated Risk 2027| High Risk 2028– )*

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year's projection in the *2024 LTRA*) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO's accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the ERAS process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the *2025 LTRA*. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see **Table 3**). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

**Table 3: MISO Base-Case Summary of Results**

| | 2027 | 2029 |
|---|---|---|
| EUE (MWh) | 797 | 31,654 |
| NEUE (ppm) | 1.13 | 42.39 |
| LOLH (hours per Year) | 0.23 | 6.61 |
| Category | Elevated | High |

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see **Figure 2**). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

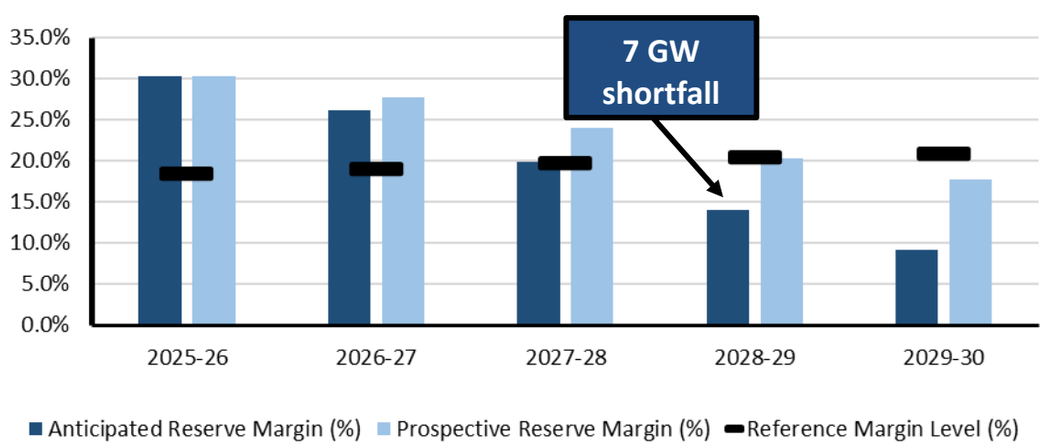
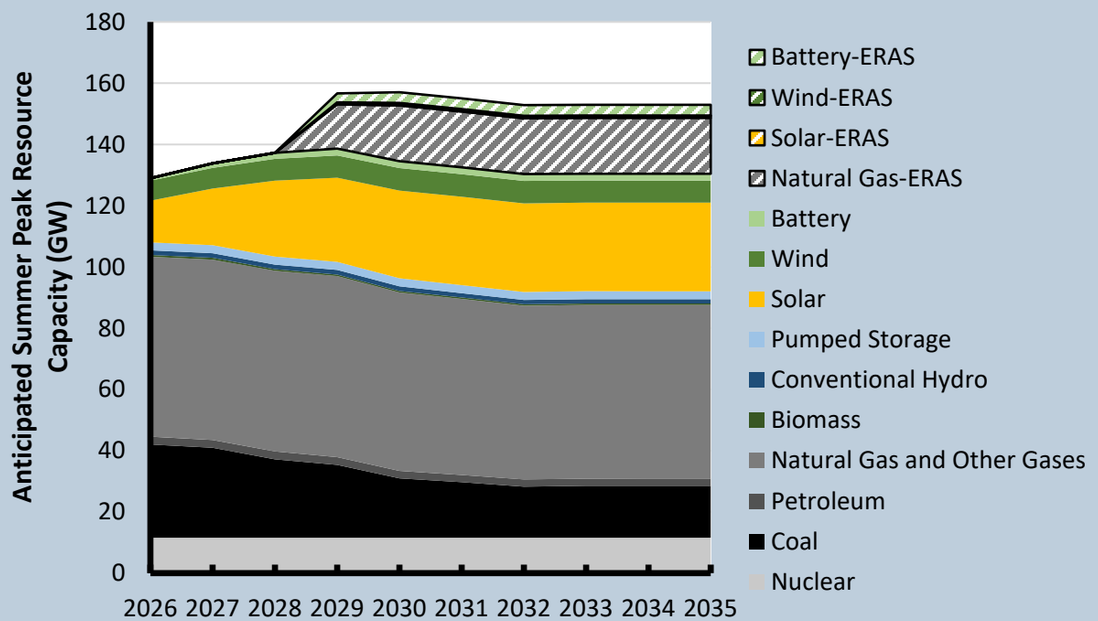



**Figure 2: MISO Winter Planning Reserve Margins**

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the *2025 LTRA*. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA*, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.




**The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity**

### *PJM (Elevated Risk 2026–2028/ High Risk 2029– )*

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM's annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year's projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM's new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM's limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM's internal generation capacity), have led to a projection that PJM's ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see **Figure 3**).

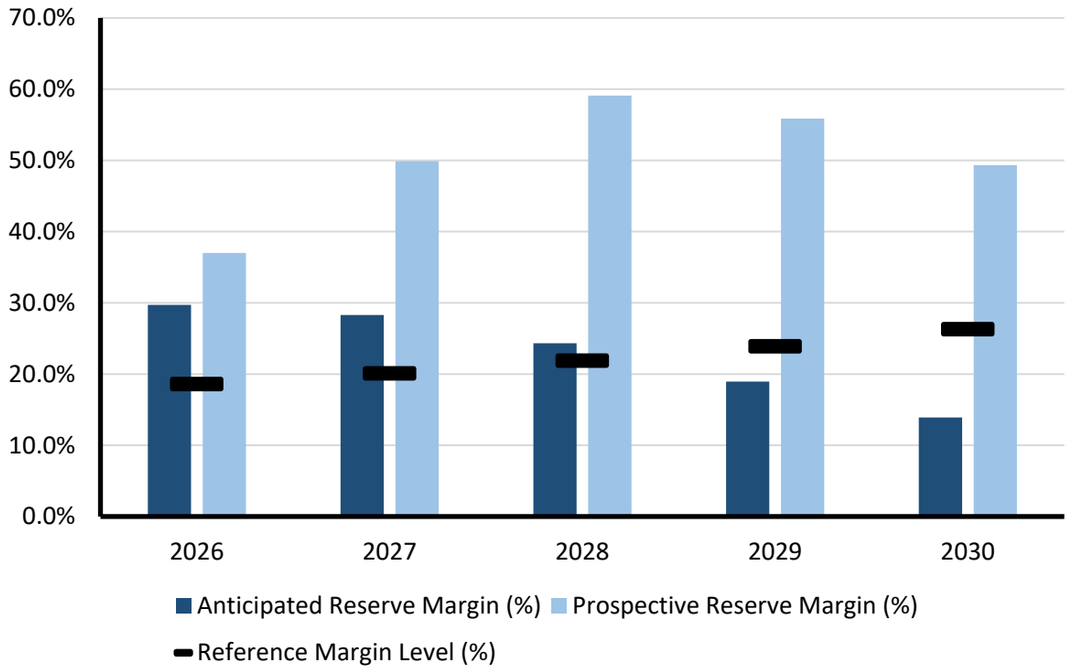



**Figure 3: PJM Summer Planning Reserve Margins**

As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM's new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original *2025 LTRA* data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM's current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see **Table 4**). Because this year's ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year's LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

**Table 4: PJM Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | 538 | 3,251 | 67,581 |
| NEUE (ppm) | 0.00 | 3.50 | 65.50 |
| LOLH (hours per Year) | 0.1 | 0.61 | 9.97 |
| Category | Elevated | Elevated | High |

***Provides the 2024 ProbA Results for Comparison**

### *Texas RE-ERCOT (Elevated Risk 2026–2028| High Risk 2029– )*

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the *2025 LTRA*, ERCOT's DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the *2024 LTRA*), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see **Figure 4**).

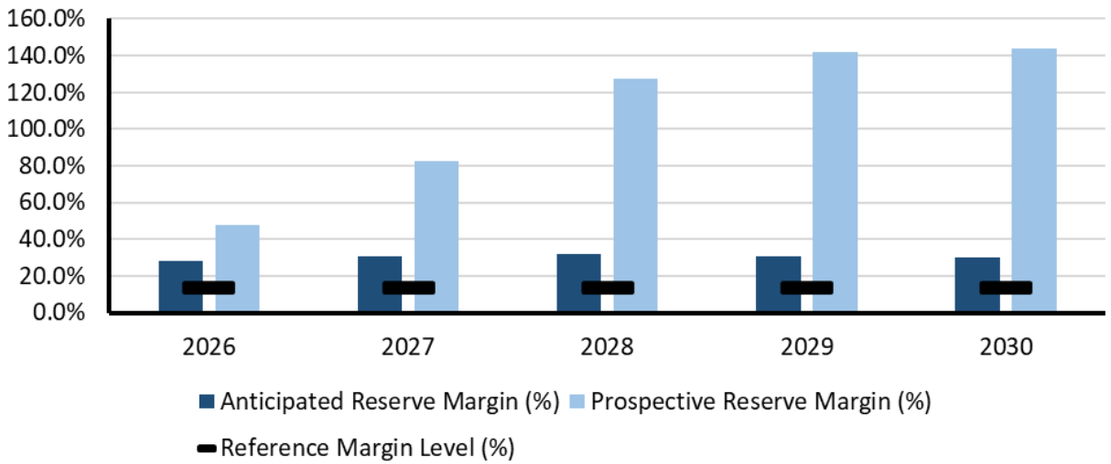



**Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins**

ERCOT's Planning Reserve Margins in the *2025 LTRA* are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the *2024 LTRA*, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see **Table 5**). ERCOT's ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT's market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

**Table 5: Texas RE-ERCOT Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | 11,090 | 5,865 | 17,053 |
| NEUE (ppm) | 18.95 | 8.70 | 18.84 |
| LOLH (hours per Year) | 1.57 | 0.95 | 3.64 |
| Category | Elevated | Elevated | High |
| ***Provides the 2024 ProbA Results for Comparison** | | | |

ERCOT's ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

### *WECC-Basin (Elevated Risk 2026–2028/High Risk 2029– )*

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.[16] The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see Table 6).

**Table 6: WECC Basin Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | N/A | 3 | 200,892 |
| NEUE (ppm) | N/A | 0.04 | 2,250.70 |
| LOLH (hours per Year) | N/A | 3.00 | 310.00 |
| Category | - | High | High |
| ***No prior results as the assessment area is new for the *2025 LTRA*.** | | | |

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC's probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

### *WECC-Northwest (Normal Risk 2026–2028| High Risk 2029– )*

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see Table 7).

**Table 7: WECC Northwest Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | N/A | 0 | 8,080 |
| NEUE (ppm) | N/A | 0.00 | 36.64 |
| LOLH (hours per Year) | N/A | 0.00 | 85.00 |
| Category | N/A | Normal | High |
| ***No prior results as the assessment area is new for the *2025 LTRA*.** | | | |

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

## Elevated-Risk Area Details

The below areas are classified as Elevated Risk as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the Regional Assessments Dashboards section.

### *MRO-Manitoba Hydro (Normal 2026–2028| Elevated 2029– )*

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the *2024 LTRA*. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the *2024 LTRA*. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro's 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see Table 8). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

[16] Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

| Table 8: MRO-Manitoba ProbA Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 5 | 3 | 6 |
| NEUE (ppm) | 0.18 | 0.12 | 0.23 |
| LOLH (hours per Year) | 0.06 | 0.03 | 0.06 |
| Category | Normal | Normal | Elevated |
| *** Provides the 2024 ProbA Results for Comparison** | | | |

### *MRO-SaskPower (Elevated 2026–2027| Normal 2028– )*

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the *2024 LTRA*'s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year's projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower's RML for the entire 10-year period of the *2025 LTRA*.

SaskPower is a winter-peaking system, but MRO-Saskatchewan's probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower's projected resource additions (see **Table 9)**.

| Table 9: MRO-SaskPower Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 76 | 145 | 5 |
| NEUE (ppm) | 2.81 | 5.24 | 0.19 |
| LOLH (hours per Year) | 0.55 | 1.09 | 0.05 |
| | Elevated | Elevated | Normal |
| ***Provides the 2024 ProbA Results for Comparison** | | | |

### *MRO-SPP (Elevated 2026– )*

Resource additions and delays in generator retirements since the *2024 LTRA* are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP's ARMs are projected to remain above RMLs until after 2030 (see **Figure 5**). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.[17] SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

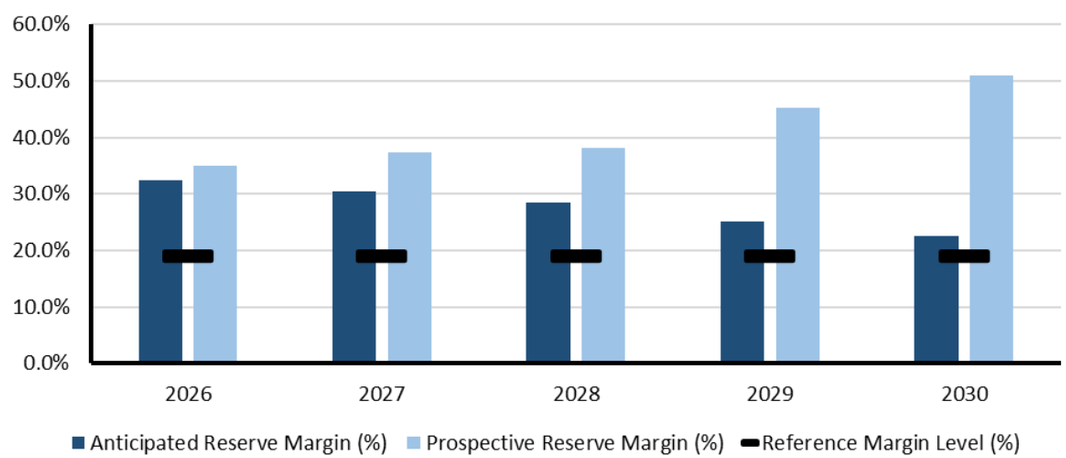



**Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer**

[17] See NERC *2025 Summer Reliability Assessment*

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

### *NPCC-Maritimes (Elevated 2026– )*

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see **Table 10**). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

**Table 10: NPCC-Maritimes Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | 5 | 15 | 7 |
| EUE (ppm) | 0.17 | 0.52 | 0.25 |
| LOLH (hours per Year) | 0.09 | 0.25 | 0.10 |
| ***Results from the 2024 The ProbA simulations** | | | |

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

### *NPCC-New England (Normal 2026 –2028| Elevated 2029– )*

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see **Table 11**). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

**Table 11: NPCC New England Base-Case Summary of Results**

| | 2026* | 2027 | 2029 |
|---|---|---|---|
| EUE (MWh) | 11 | <1 | 2 |
| NEUE (ppm) | 0.10 | 0.00 | 0.02 |
| LOLH (hours per Year) | 0.10 | 0.00 | 0.00 |
| Category | Normal | Normal | Normal |
| *** Provides the 2024 ProbA results for Comparison** | | | |

### *NPCC-New York (Elevated 2026– )*

The LTRA anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in **Table 12.**

| Table 12: NPCC New York Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 2 | <1 | 12 |
| NEUE (ppm) | 0.01 | 0.00 | 0.08 |
| LOLH (hours per Year) | 0.01 | 0.00 | 0.03 |
| Category | Normal | Normal | Normal |
| *** Provides the 2024 ProbA results for Comparison** | | | |

While NPCC's ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the ***2025 Quarter 3 Short-Term Assessment of Reliability*** **(STAR)**,[18] identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

### *NPCC-Québec (Normal 2026–2028| Elevated 2029– )*

Québec's demand forecast has increased since the *2024 LTRA*, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec's demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the *2024 LTRA*.

With stable resources over the 10-year assessment period, Québec's ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See **Table 13**.

| Table 13: NPCC Québec Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 8 | 8 | 63 |
| NEUE (ppm) | 0.04 | 0.00 | 0.29 |
| LOLH (hours per Year) | 0.01 | 0.00 | 0.11 |
| Category | Normal | Normal | Elevated |
| *** Provides the 2024 ProbA results for Comparison** | | | |

### *SERC-East (Normal 2026| Elevated 2027– )*

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in **Table 14** below.

| Table 14: SERC-East ProbA Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 143 | 232 | 539 |
| NEUE (ppm) | 0.60 | 0.98 | 2.27 |
| LOLH (hours per Year) | 0.09 | 0.15 | 0.33 |
| Category | Normal | Elevated | Elevated |
| *** Provides the 2024 ProbA Results for Comparison** | | | |

[18] Additional details available in the report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/

### Normal-Risk Area Details

All other assessment areas (see Figure 1) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

## Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2025 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

### Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding **Capacity and Energy Risk Assessment**, NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC's risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the *2024 LTRA* (see **Figure 6**). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year's LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

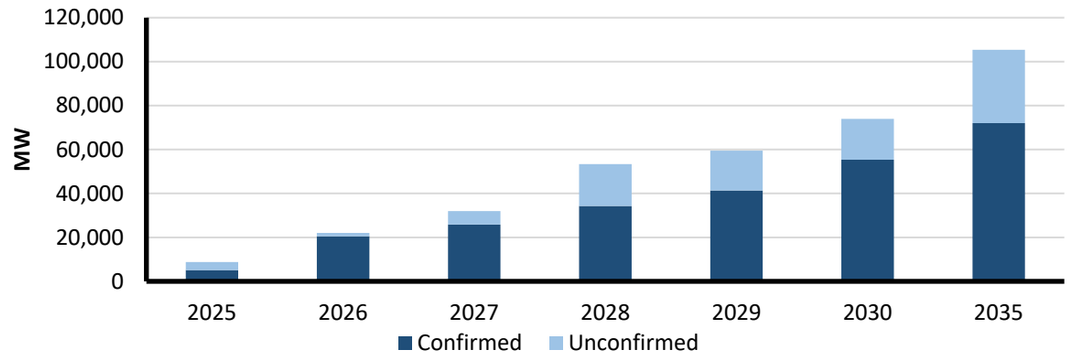



**Figure 6: Projected Generation Retirement Capacity Through 2035**

**Figure 7** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from Additional Generator Retirements** section.

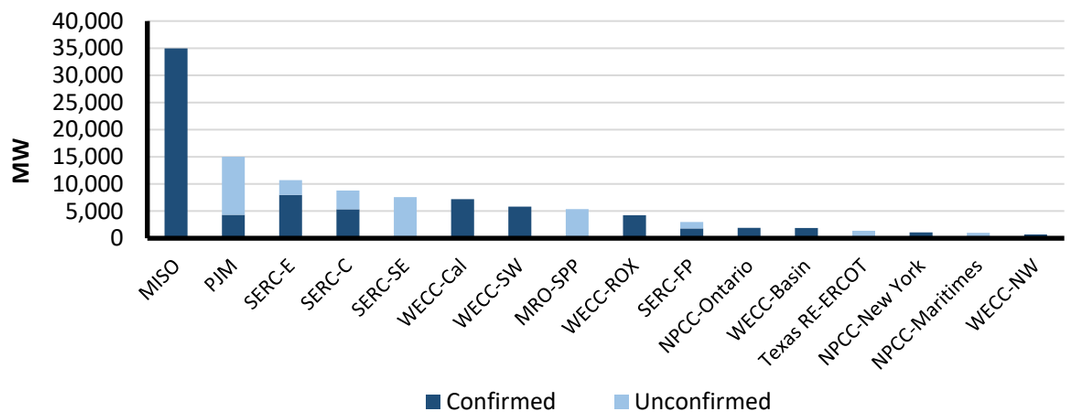



**Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035**

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2025 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

## Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Executive Summary**.

### Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. **Table 15** includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

**Table 15: Resource Adequacy Program Attributes**

| Attributes | Objective | Implementation |
|---|---|---|
| **1. Uses Energy Risk Criteria** | To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics. | Establish criteria based on EUE or similar energy risk metric(s). |
| **2. Evaluates Resource Contributions at Risk Periods** | As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve. | Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods. |
| **3. Load Forecasting Accounts for Growth Uncertainty** | Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty. | Capture the forecast drivers needed for the area and address uncertainties. |
| **4. Considers Effect of Extreme Scenarios on Adequacy** | To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS. | Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration. |
| **5. Includes Coordinated Interregional Transfer Capability** | Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors. | Model transfer limits and deliverability; implement processes for seams coordination. |

# Demand Trends and Implications

## Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See **Figure 8** for seasonal peak demand growth over the current and prior assessment periods and **Figure 9** for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year's 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC's tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 10.**

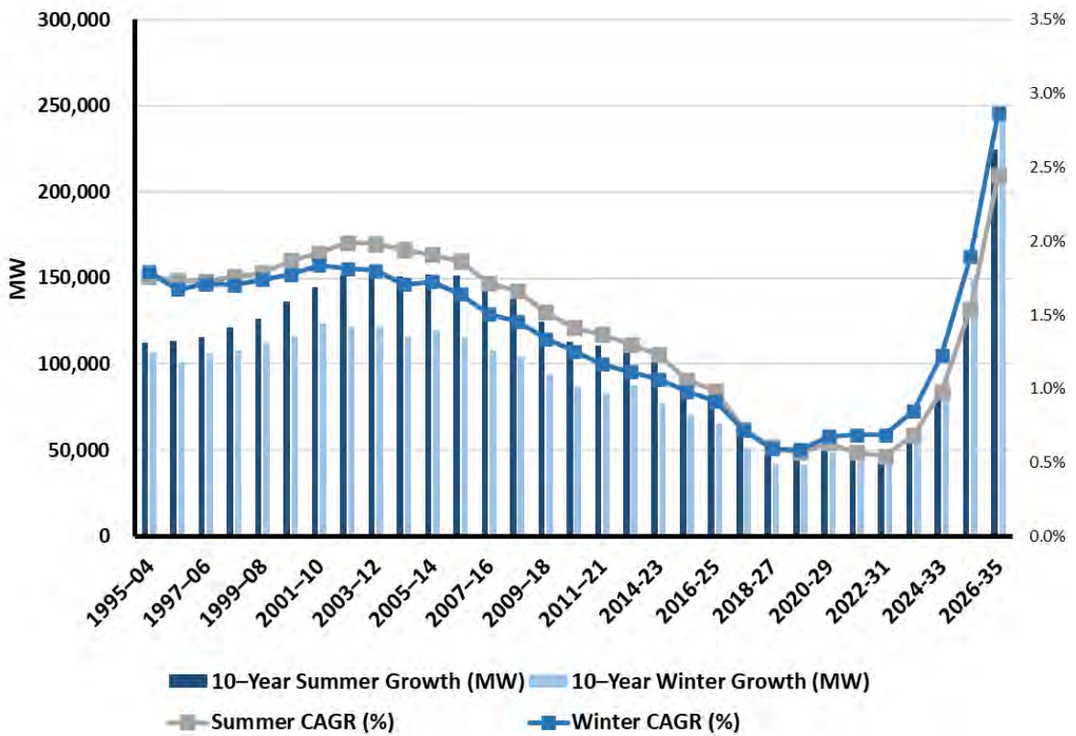



**Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends**

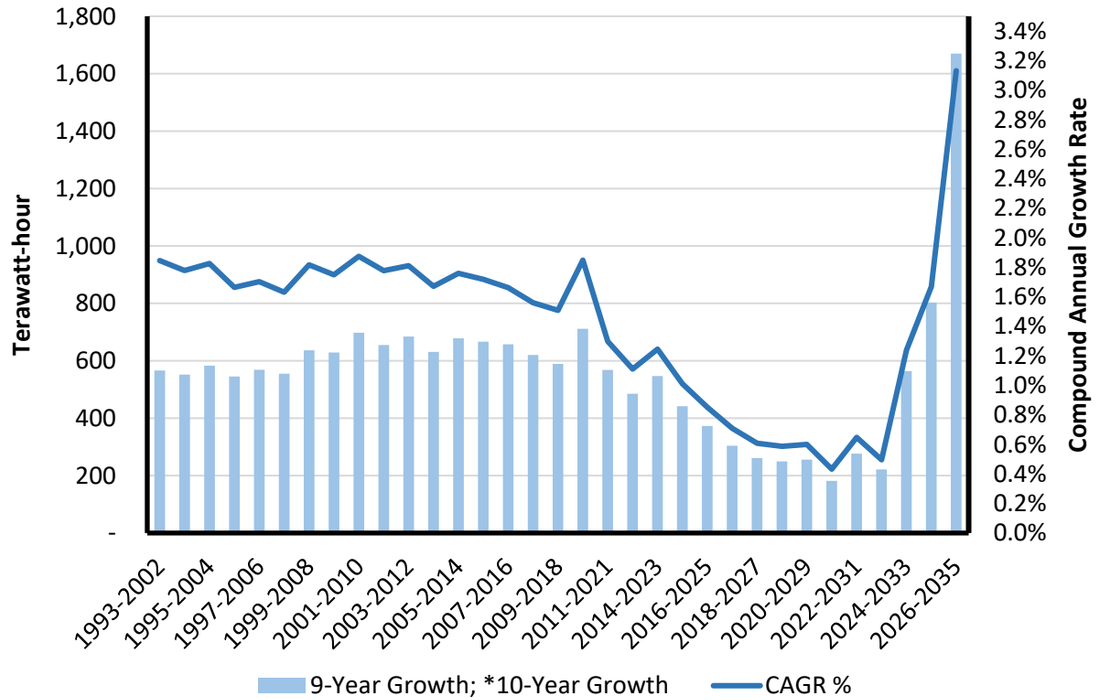



**Figure 9: Net Energy for Load Growth and Rate Projections**

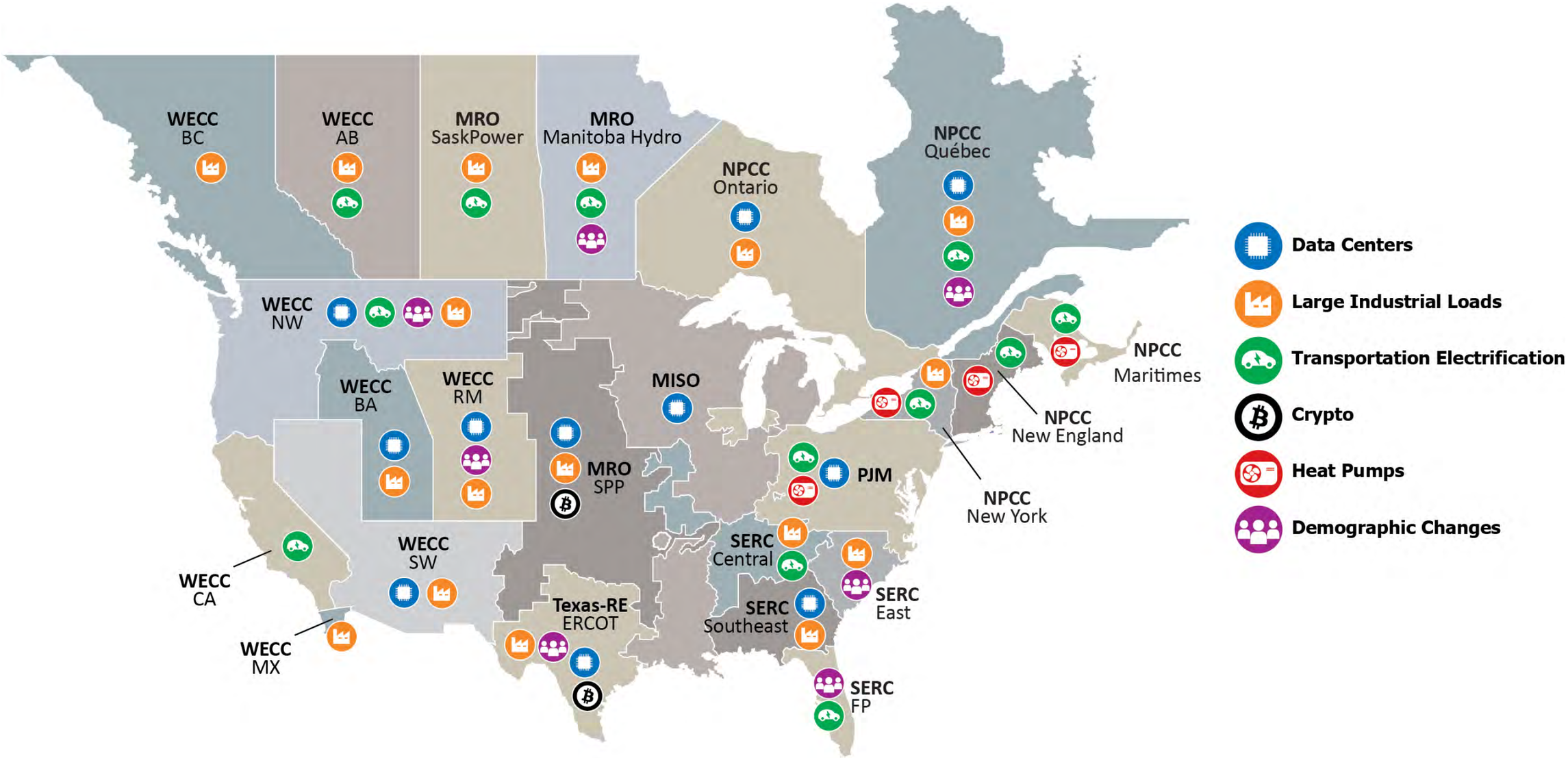



**Figure 10: Primary Demand Drivers by Assessment Area**

## Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the *2025 LTRA* reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See **Figure 11** and **Figure 12** for projections in ERCOT and most WECC assessment areas, respectively.

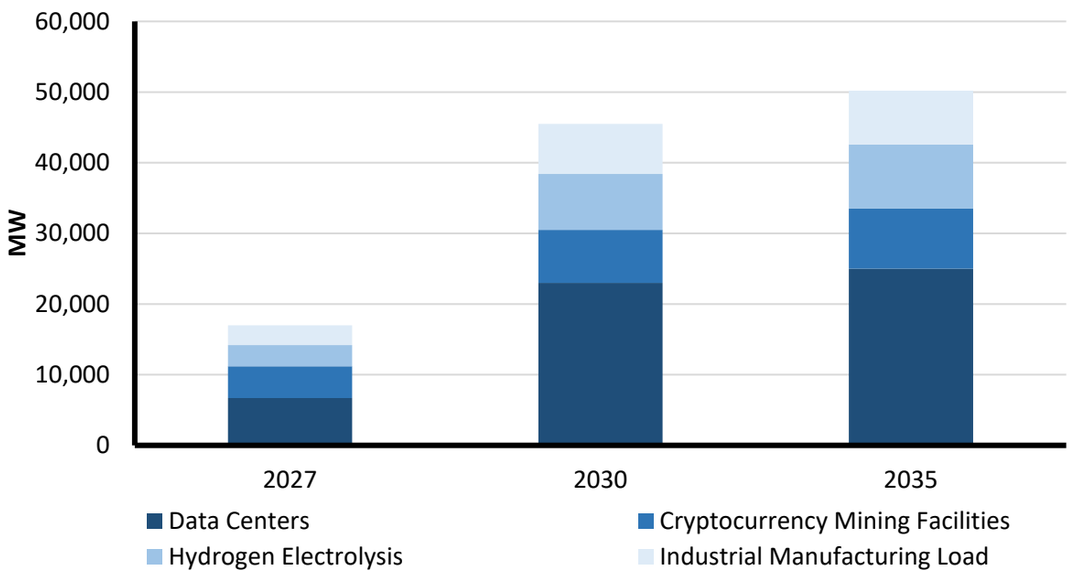



**Figure 11: Large-Load Projection Breakdown in ERCOT**

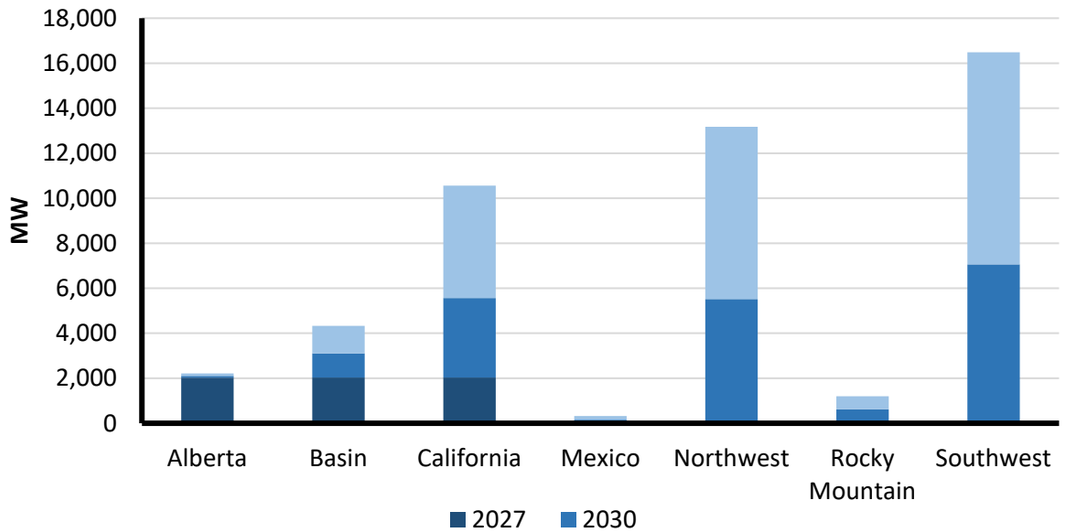



**Figure 12: Large-Load Projection by Year in WECC Assessment Areas**

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.[20]

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events[21] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC's RSTC established a Large Loads Task Force (LLTF)[22] to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*[23] in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.[24]

## Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2024 LTRA*, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro's winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower's winter CAGR fell from 1.32% to 0.89%, NPCC-New England's summer CAGR from 1.28% to 1.05%, NPCC-New York's summer CAGR from 0.87% to 0.84%, and SERC-East's summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

## Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

## Demand Response

Demand-side management programs are growing for many assessments areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. **Figure 13**, **Figure 14**, and **Figure 15** show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

[20] Planned revisions to PJM's treatment of large load forecasts from PJM's Load Analysis Subcommittee: 20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf

[21] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

[22] NERC Large Loads Task Force webpage: Large Loads Task Force (LLTF)

[23] The LLTF's *Characteristics and Risks of Emerging Large Loads* White Paper

[24] The LLTF's action plan is updated regularly and contains links to white papers, guidance, and presentations.

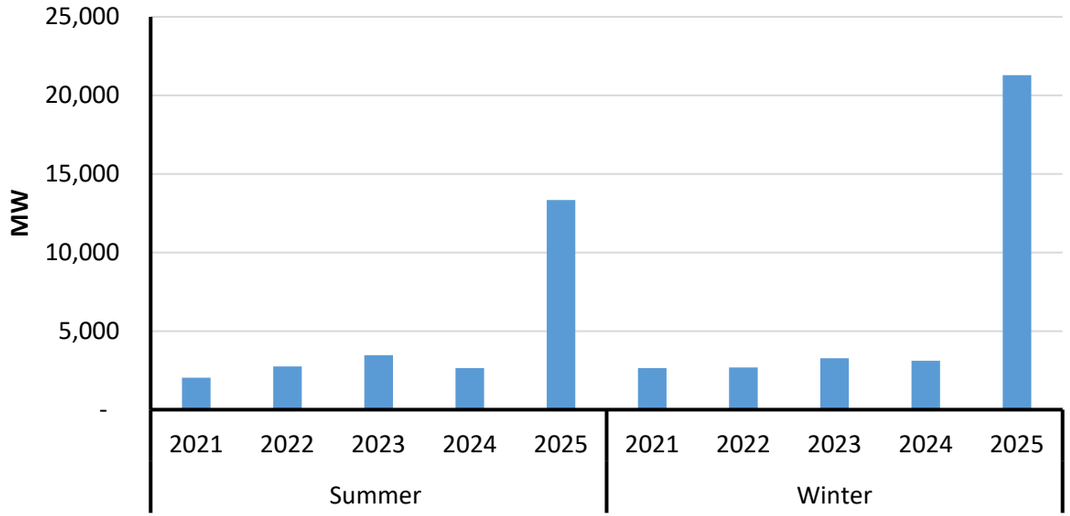



**Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)**

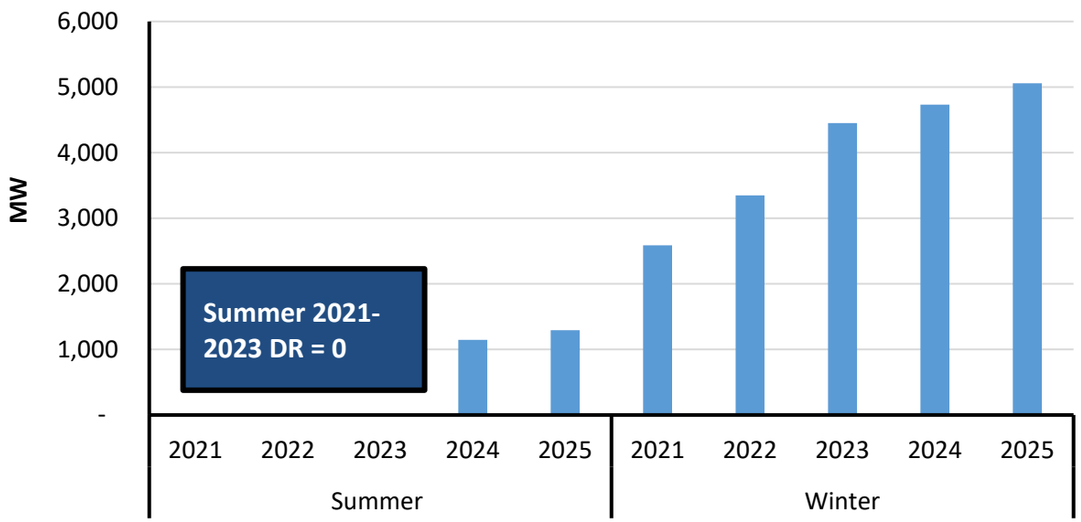



**Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)**

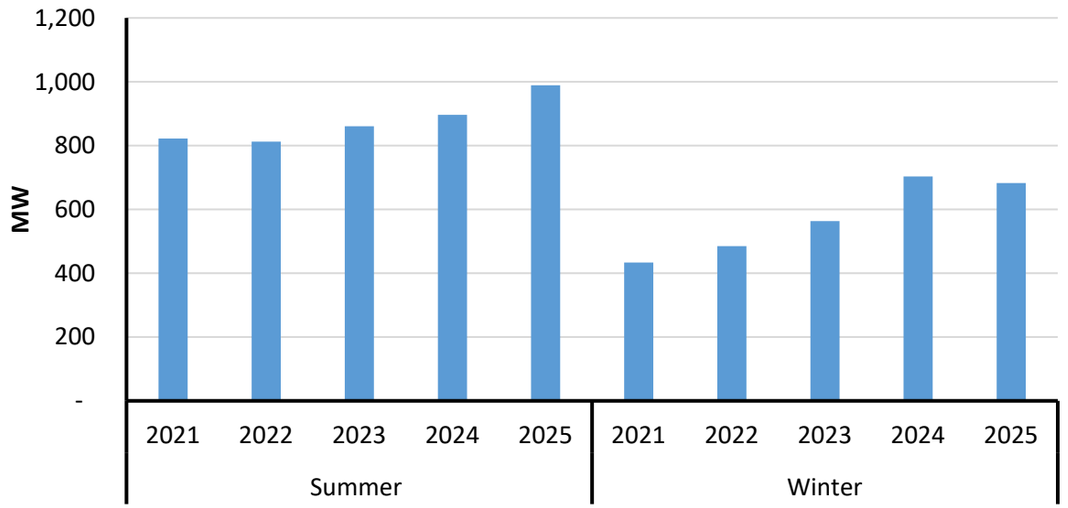



**Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)**

## Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year noticeably affected resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

## Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see Table 16).

**Table 16: Existing BPS Resource On-Peak Capacity**

| Resource Type | 2024 Capacity (MW) | 2025 Capacity (MW) | Difference (MW) |
|---|---|---|---|
| **Coal** | 180,402 | 166,799 | – 13,603 |
| **Petroleum** | 30,987 | 27,931 | – 3,056 |
| **Natural Gas** | 484,148 | 479,901 | – 4,247 |
| **Biomass** | 7,381 | 7,181 | – 200 |
| **Solar** | 66,293 | 70,723 | + 4,430 |
| **Wind** | 31,370 | 35,121 | + 3,751 |
| **Geothermal** | 3,881 | 2,932 | – 949 |
| **Conventional Hydro** | 105,792 | 111,117 | + 5,325 |
| **Run-of-River Hydro** | 2,047 | 2,017 | – 30 |
| **Pumped Storage** | 19,422 | 19,734 | + 312 |
| **Nuclear** | 105,384 | 105,389 | + 5 |
| **Hybrid** | 1,322 | 1,102 | – 220 |
| **Other** | 774 | 830 | + 56 |
| **Battery** | 8,587 | 23,267 | + 14,680 |
| **Total** | 1,047,790 | 1,068,514 | + 6,254 |

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

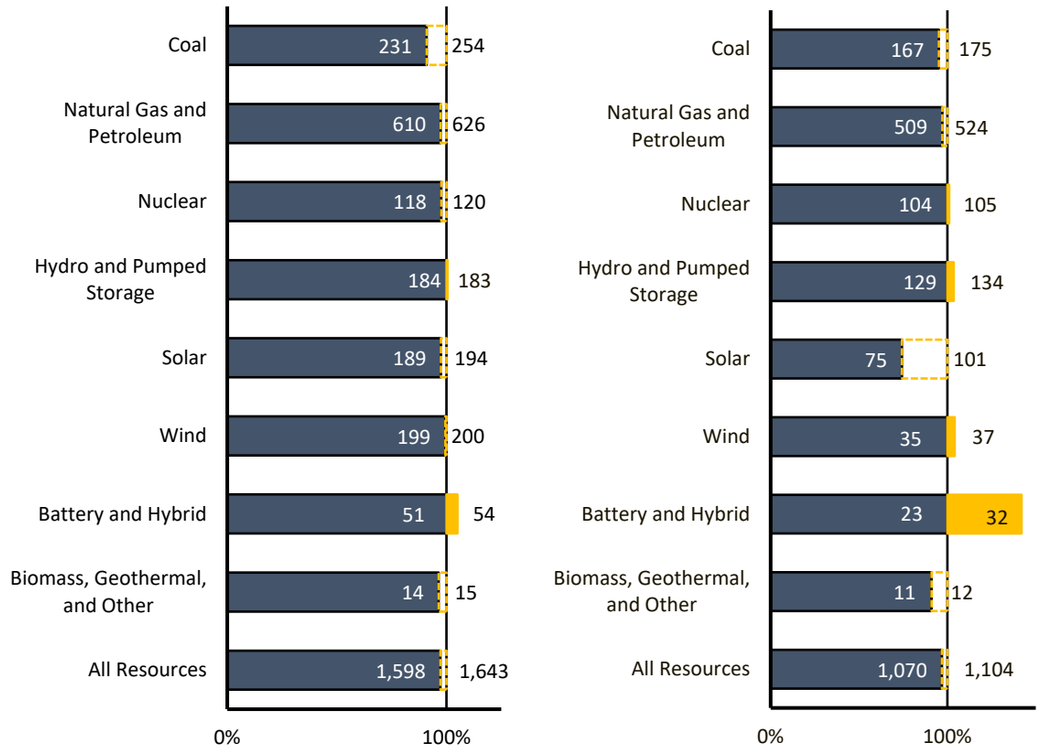



**Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections**

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in Figure 16 above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

## Planned On-Peak Capacity Additions

New resources are added to the BPS through each area's interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. **Figure 16** above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

**Figure 17** illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see **Demand Assumptions and Resource Categories**). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see **Figure 18**). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in **Figure 17**, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2's 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM's Reliability Resource Initiative, MISO's ERAS process, and SPP's *Expedited Resource Adequacy Study*.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

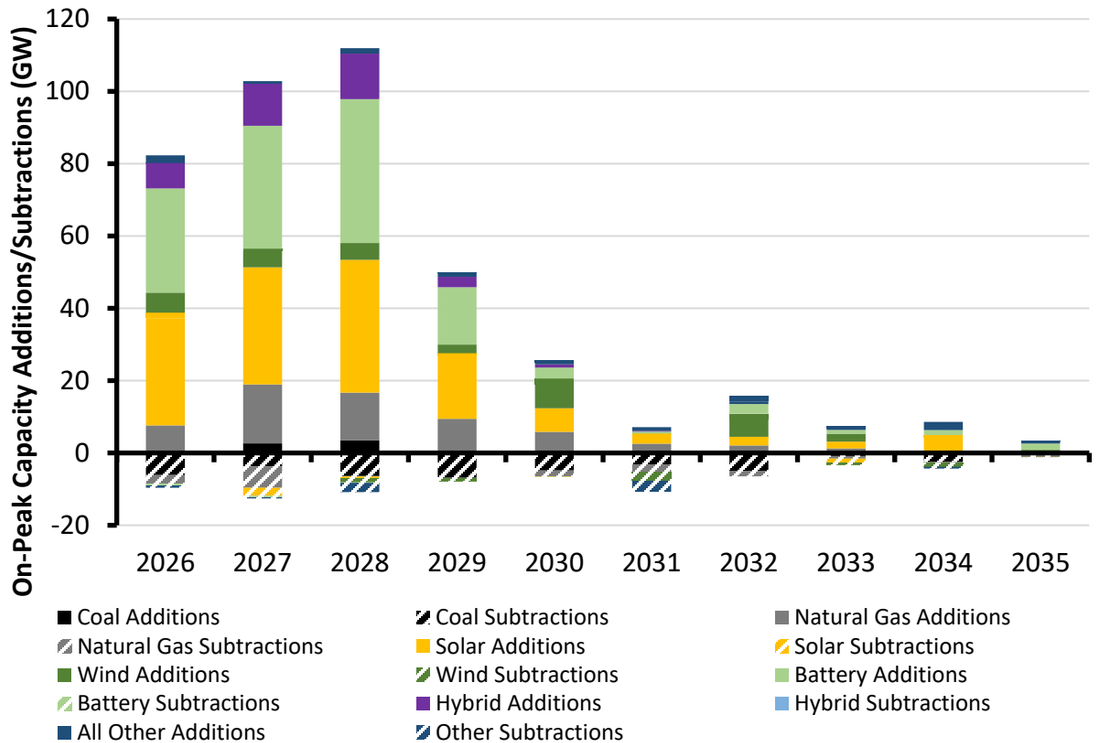



**Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes**

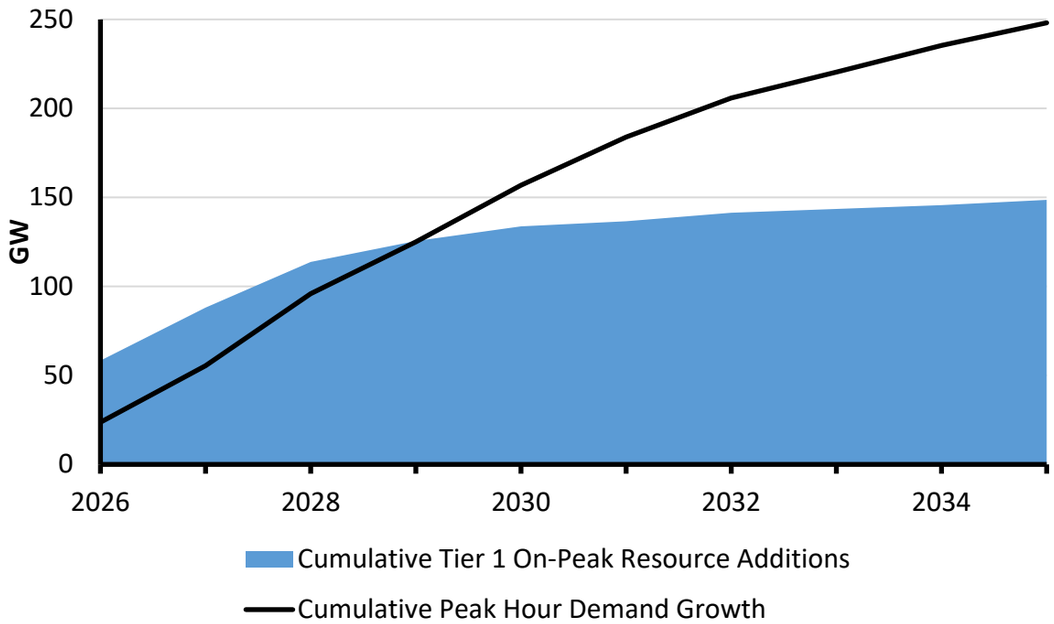



**Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035**

### Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. **Figure 19** shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

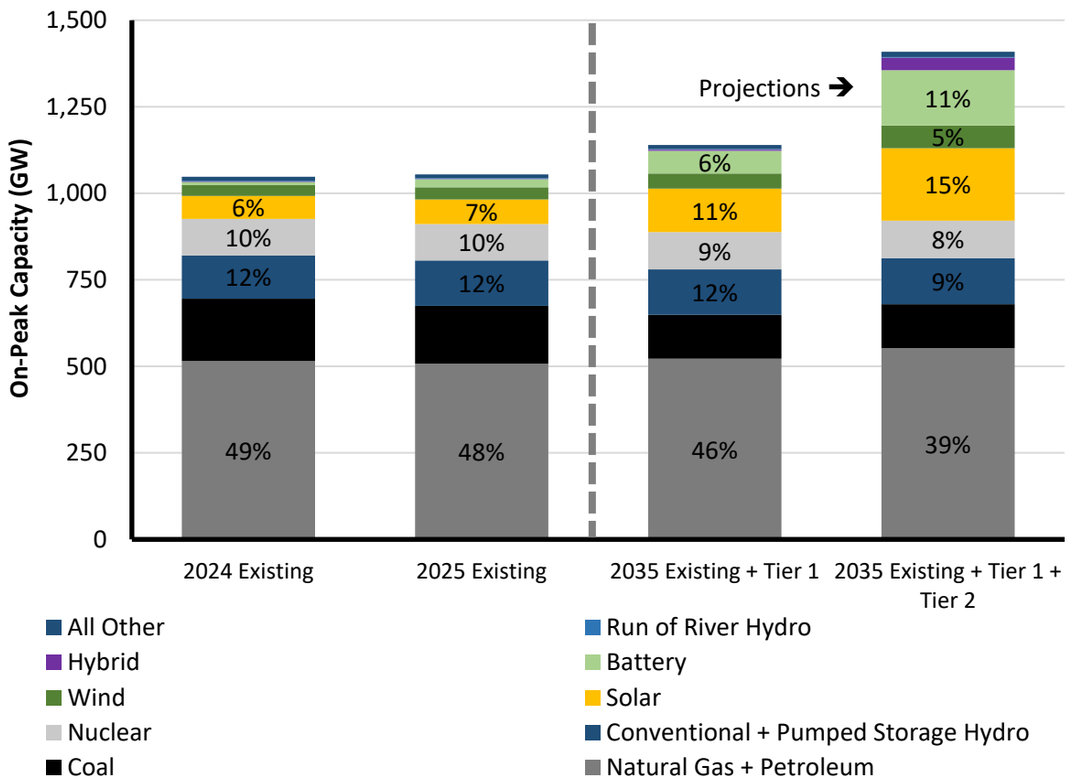



**Figure 19: North America On-Peak Capacity Shares by Resource Type**

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

## System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the *2025 LTRA*, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in Table 17.

**Table 17: Measures of Frequency Response**

| Measure | What it Measures | Summary Assessment Findings |
|---|---|---|
| **Synchronous Inertial Response (Measure 1)** | The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection | Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions. |
| **Rate of Change of Frequency (Measure 2)** | The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency | No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly. |
| **Frequency Response Performance (Measure 4)** | Simulated dynamic behavior of an Interconnection's response to the largest credible contingency | Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases. |

The results of analysis for each Interconnection are in Table 18. Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

**Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment**

| Interconnection | Highest Non-Synchronous Penetration at Minimum Inertia Studied | Number of Critical Inertia Conditions Reached? | Lowest Frequency Nadir Observed in Planning Studies | Likelihood of Credible Disturbance Resulting in UFLS Activation |
|---|---|---|---|---|
| **Eastern Interconnection** | 17.9%[25] | 0 | 59.93 Hz | Low |
| **Western Interconnection** | 42.9%[26] | 0 | 59.65 Hz | Low |
| **Texas Interconnection** | 65.7% | 0 | N/A | Low[27] |
| **Québec Interconnection** | 37% | 0 | N/A | Low |

## Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation's share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

[25] EIPC Frequency Response Report

[26] 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

[27] ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see **Figure 20**). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today's energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection's Reliability Resource Initiative has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO's ERAS include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP's *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

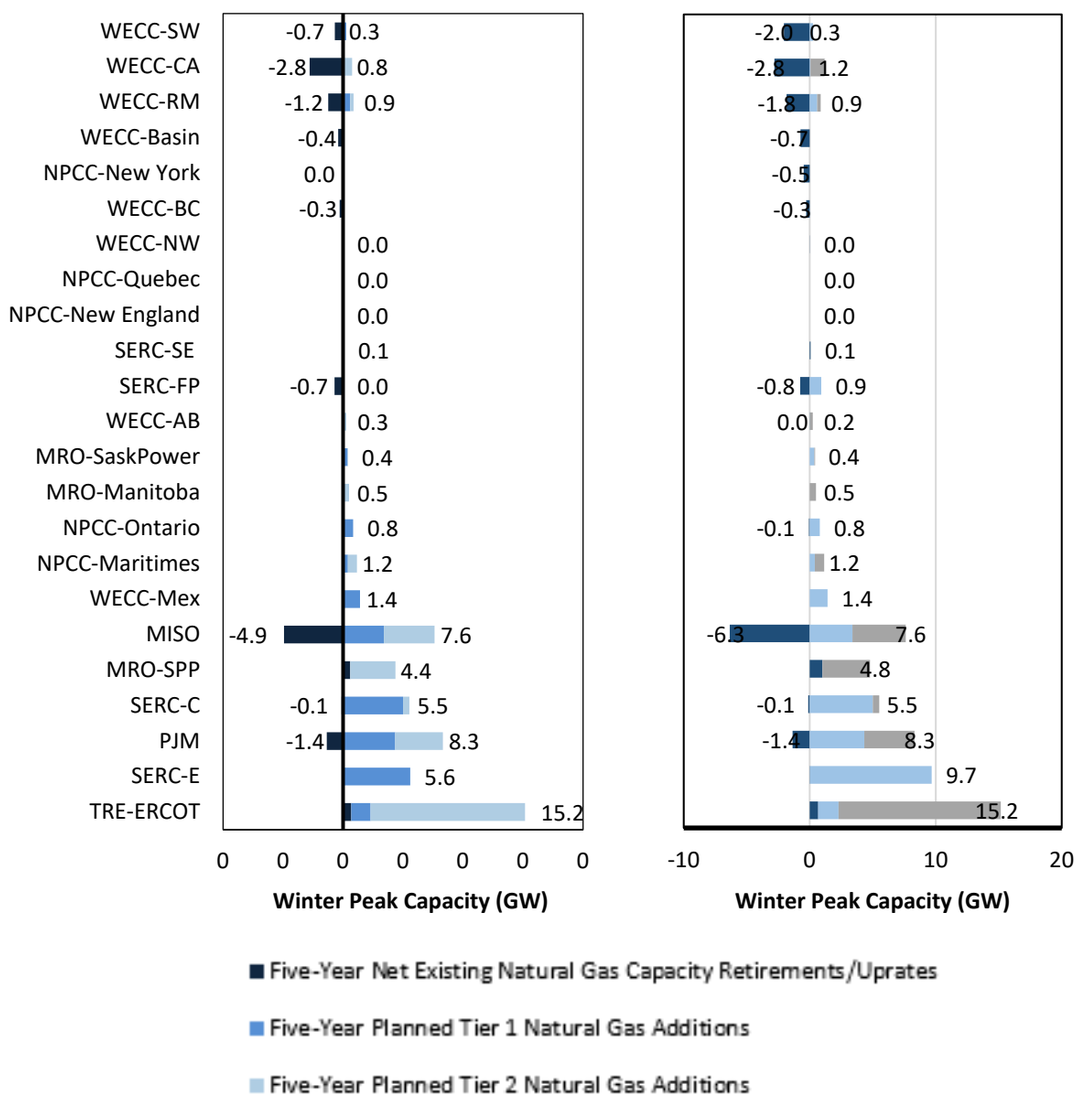



**Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area**

## Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers' supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

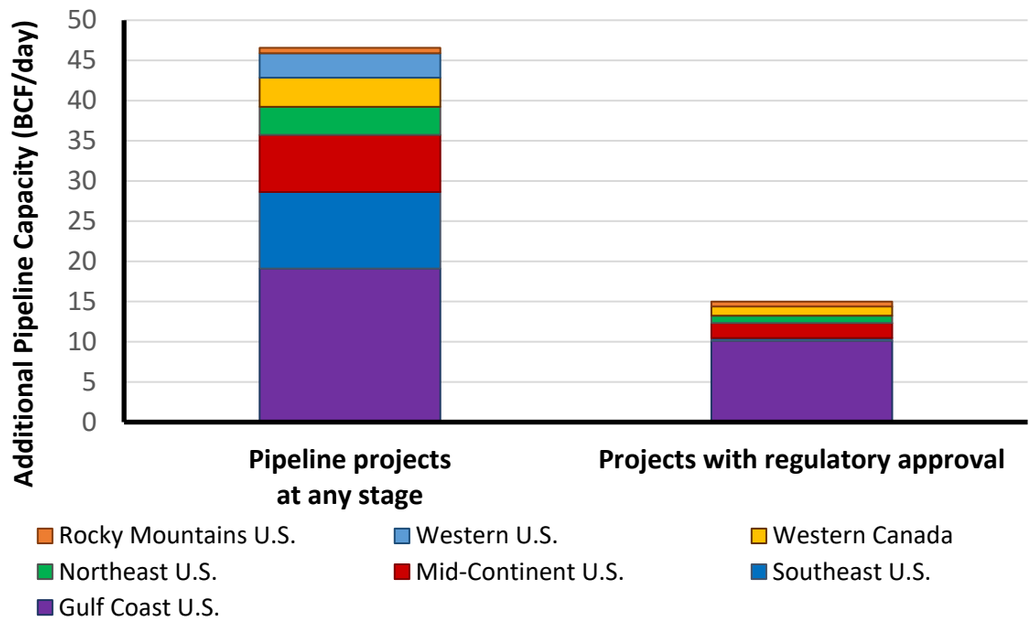



**Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)**

The nearly 40 GW of natural-gas-fired  winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see **Figure 22**), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

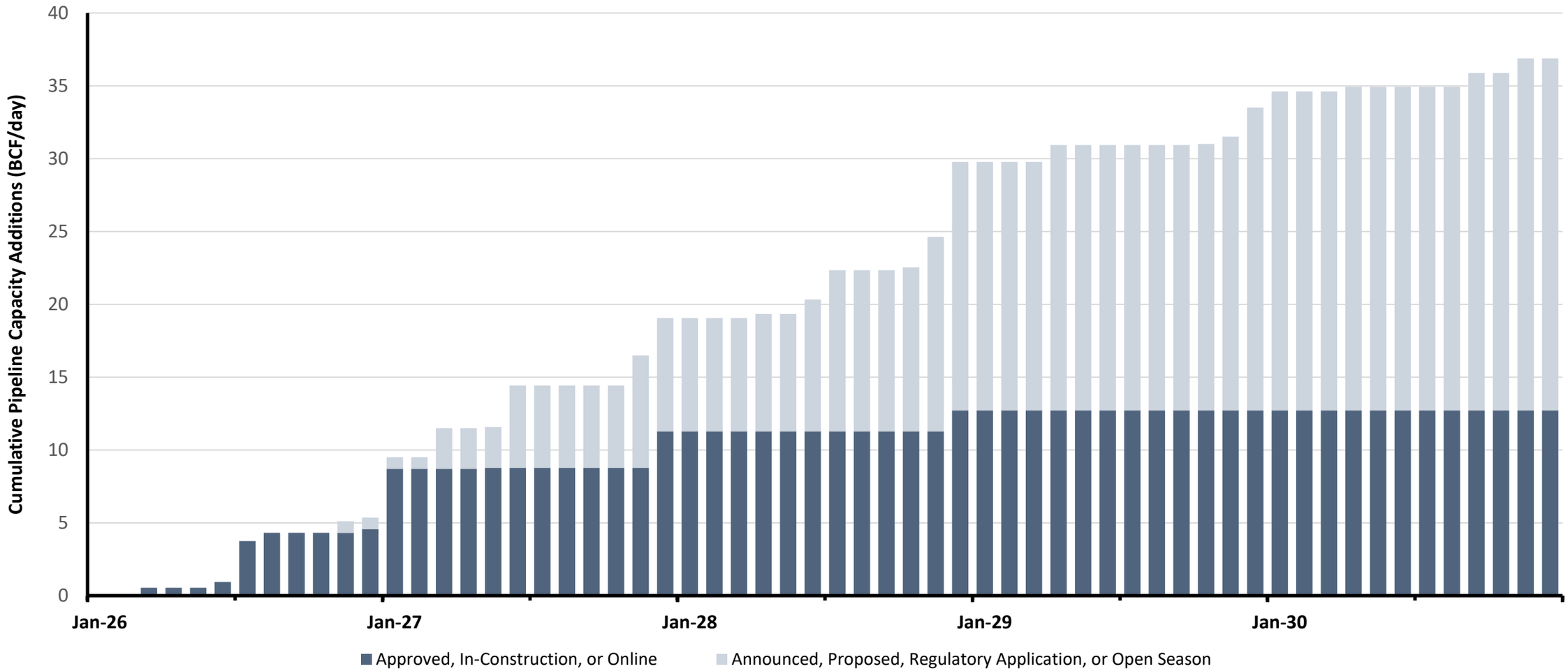



**Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)**

# Transmission Development and Interregional Transfer Capability

## Transmission Projects

This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see **Figure 23**) is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

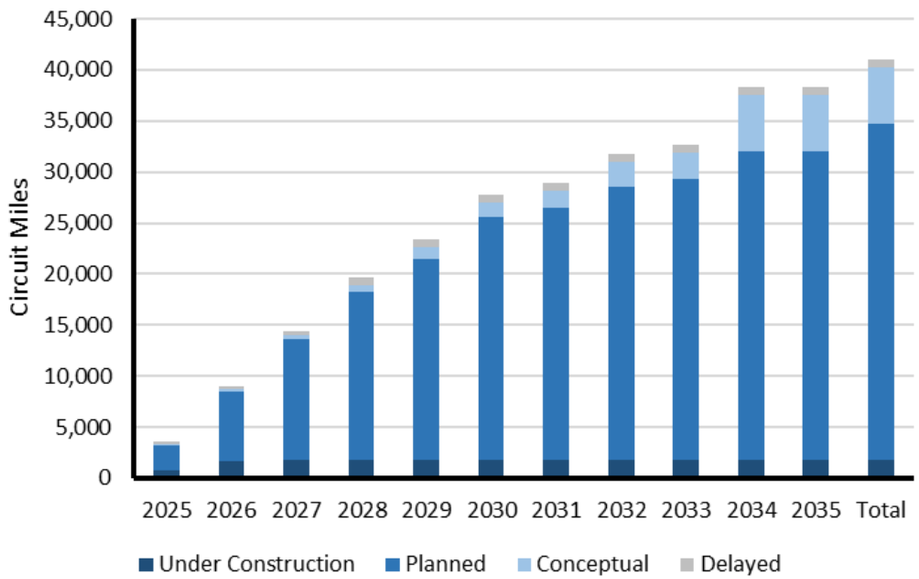



**Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]**

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec's plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. **Figure 24** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

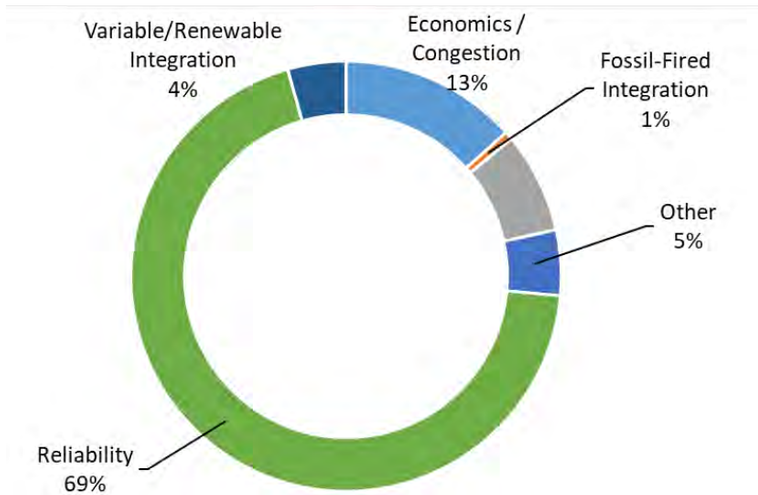



**Figure 24: Future Transmission Circuit Miles by Primary Driver**

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[29] including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year's LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalaches-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

[28] The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

[29] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* | Federal Energy Regulatory Commission

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

## Interregional Transfer Capability Study (Canadian Analysis)

In the *2024 LTRA*, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability[30] for U.S. transmission planning regions (TPR) that could support energy adequacy.[31] NERC filed the completed study report with FERC on November 19, 2024.[32] Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The *ITCS Canadian Analysis* (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

### Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in **Figure 25** and **Figure 26**, respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR[33] but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

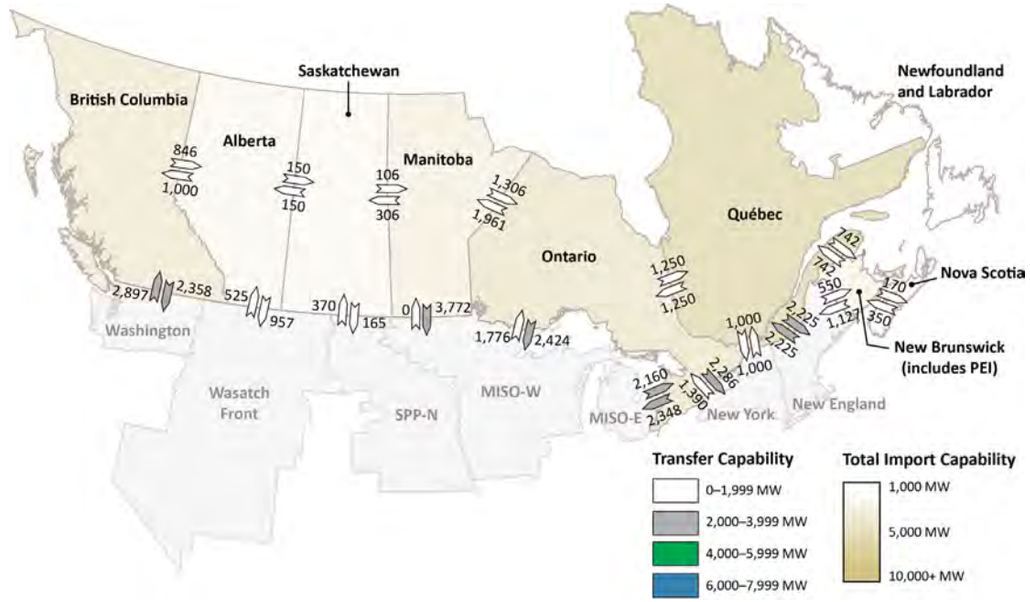



**Figure 25: Transfer Capabilities (Summer)**

[30] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[31] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

[32] NERC filing of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

[33] Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

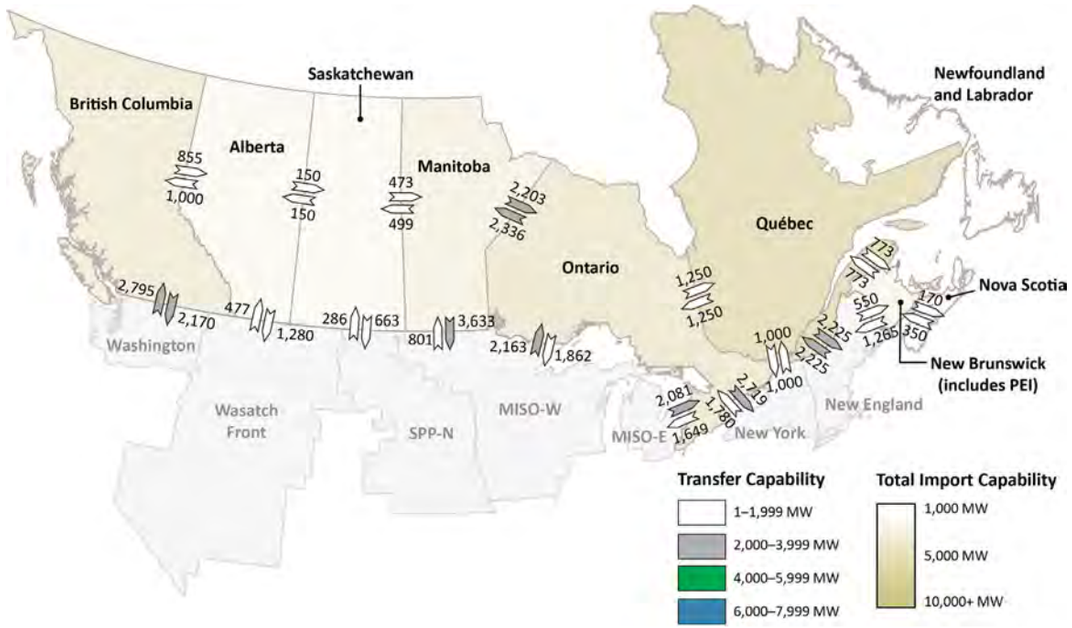



**Figure 26: Transfer Capabilities (Winter)**

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

## Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

### Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.[34] Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the *2023 LTRA* using the current transfer capabilities.[35] The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC's role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[34] This study did not incorporate climate change models.

[35] The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

## Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in *2024 LTRA* data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province's vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on *2023 LTRA* data. A sensitivity study using more recent forecasts, based on *2024 LTRA* data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. **Figure 27** shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

**Transfer capability additions are based on 2033 resource mix and other study assumptions**

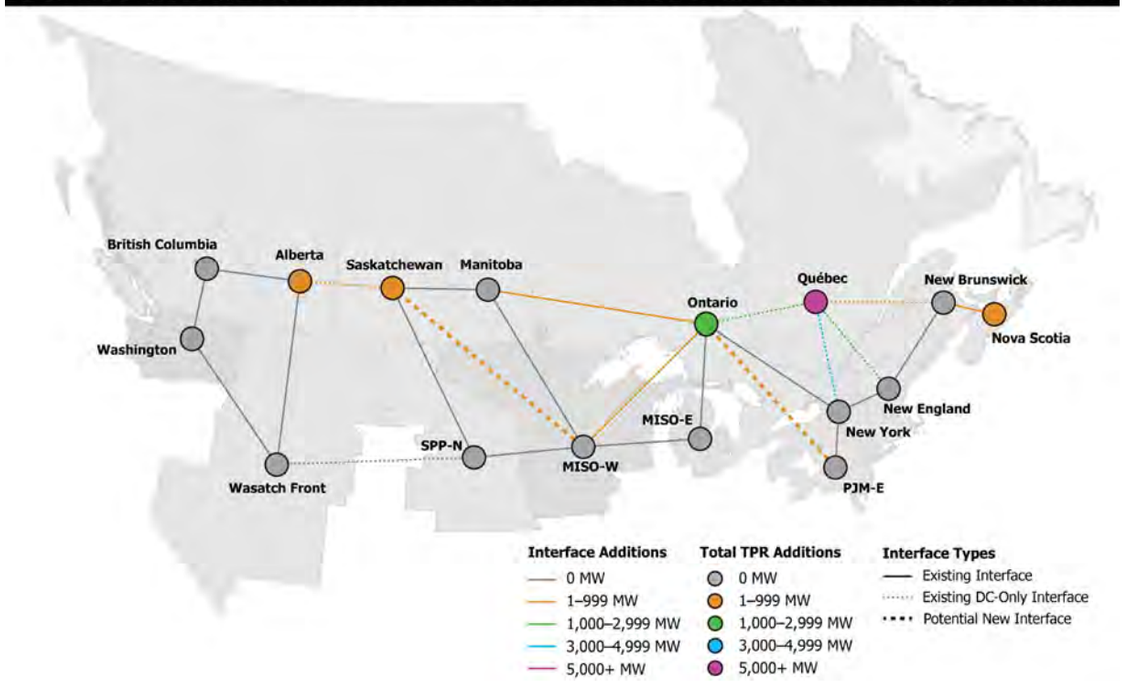
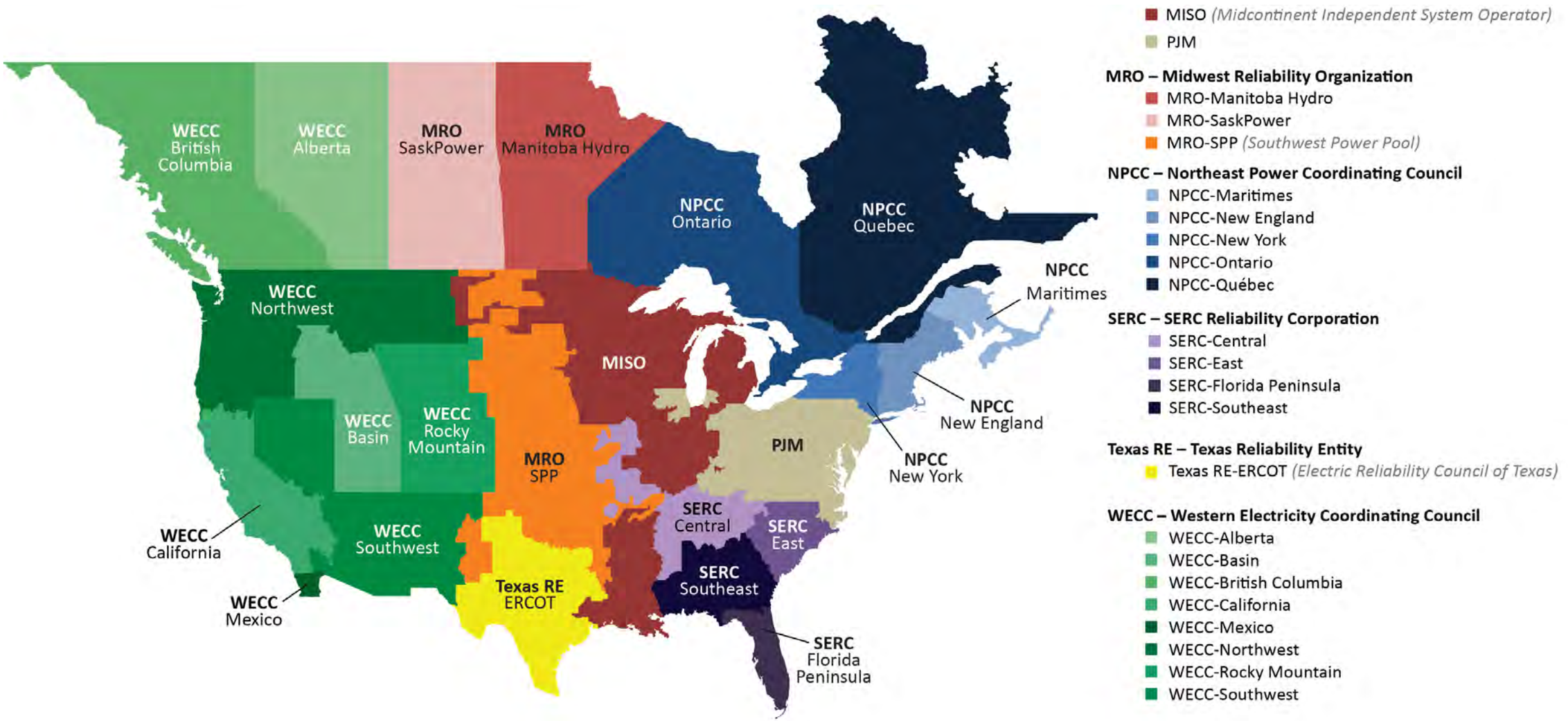



**Figure 27: Transfer Capability Additions**

## Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



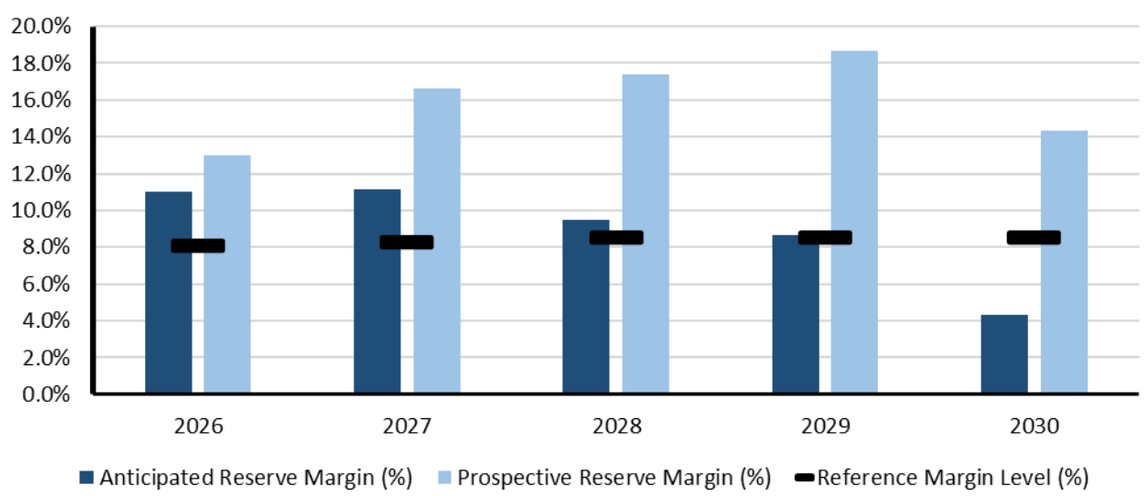


## MISO

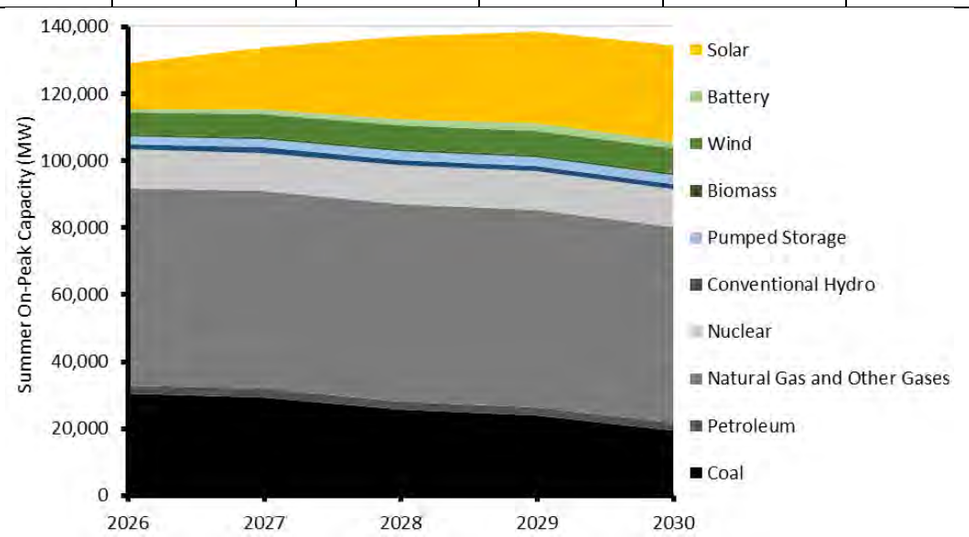
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

**Demand, Resources, and Reserve Margins (Summer)**

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 127,071 | 131,107 | 135,998 | 138,286 | 139,631 | 140,959 | 142,003 | 142,789 | 143,754 | 143,754 |
| Demand Response | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 |
| Net Internal Demand | 118,791 | 122,827 | 127,718 | 130,006 | 131,351 | 132,679 | 133,723 | 134,509 | 135,474 | 135,474 |
| Additions: Tier 1 | 5,576 | 13,339 | 21,350 | 24,631 | 26,027 | 26,320 | 26,366 | 26,366 | 26,366 | 26,366 |
| Additions: Tier 2 | 2,403 | 6,723 | 10,072 | 13,056 | 13,116 | 13,260 | 13,364 | 13,466 | 13,466 | 13,466 |
| Additions: Tier 3 | 1,632 | 4,459 | 9,395 | 14,474 | 19,823 | 23,820 | 27,983 | 27,858 | 27,915 | 28,077 |
| Net Firm Capacity Transfers | 2,809 | 2,661 | 2,509 | 2,509 | 2,419 | 2,419 | 2,419 | 2,419 | 2,419 | 2,419 |
| Existing-Certain and Net Firm Transfers | 126,263 | 123,205 | 118,481 | 116,593 | 110,996 | 108,686 | 106,448 | 106,568 | 106,553 | 106,553 |
| Anticipated Reserve Margin (%) | 11.0% | 11.2% | 9.5% | 8.6% | 4.3% | 1.8% | -0.7% | -1.2% | -1.9% | -1.9% |
| Prospective Reserve Margin (%) | 13.0% | 16.6% | 17.4% | 18.7% | 14.3% | 11.7% | 9.3% | 8.8% | 8.1% | 8.1% |
| Reference Margin Level (%) | 8.1% | 8.3% | 8.5% | 8.5% | 8.5% | 8.6% | 8.7% | 8.8% | 8.9% | 8.9% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year's assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO's accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest $30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

| MISO Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 30,442 | 29,376 | 25,620 | 23,780 | 19,384 |
| Petroleum | 2,551 | 2,551 | 2,551 | 2,551 | 2,428 |
| Natural Gas | 58,748 | 58,892 | 58,984 | 59,099 | 58,262 |
| Biomass | 585 | 580 | 516 | 515 | 512 |
| Solar | 13,586 | 18,496 | 24,792 | 27,499 | 28,629 |
| Wind | 6,576 | 6,757 | 7,139 | 7,258 | 7,379 |
| **Conventional Hydro** | 1,521 | 1,523 | 1,524 | 1,524 | 1,524 |
| Pumped Storage | 2,608 | 2,608 | 2,608 | 2,608 | 2,608 |
| Nuclear | 11,571 | 11,571 | 11,571 | 11,571 | 11,571 |
| Other | 68 | 68 | 68 | 68 | 63 |
| Battery | 774 | 1,462 | 1,950 | 2,243 | 2,243 |
| **Total MW** | **129,031** | **133,883** | **137,322** | **138,715** | **134,604** |

## MISO Assessment

MISO's guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO's Statement of Guiding Principles for more information.

**Planning Reserve Margins**

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator's equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO's LOLE Study for PY 2025–2026 estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body's purview, in which case a state-mandated PRM may be used in MISO's analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The 2025 OMS-MISO Survey indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim ERAS process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
6. Enhance allocation of resource adequacy requirements.

**Energy Risk**

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO's LOLE Study for PY 25–26, MISO has also performed additional assessments for renewable integration and regional resource evolution that touch on the topic of energy risk but are not a formal part of MISO's resource adequacy and resource planning processes.

**ProbA Results**

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO's system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO's LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO's annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

**Base-Case Summary of Results**

| | 2026* | 2027 | 2029** |
|---|---|---|---|
| EUE (MWh) | 0 | 797 | 31,654 |
| NEUE (ppm) | 0 | 1.13 | 42.4 |
| LOLH (hours per Year) | 0 | 0.23 | 6.61 |

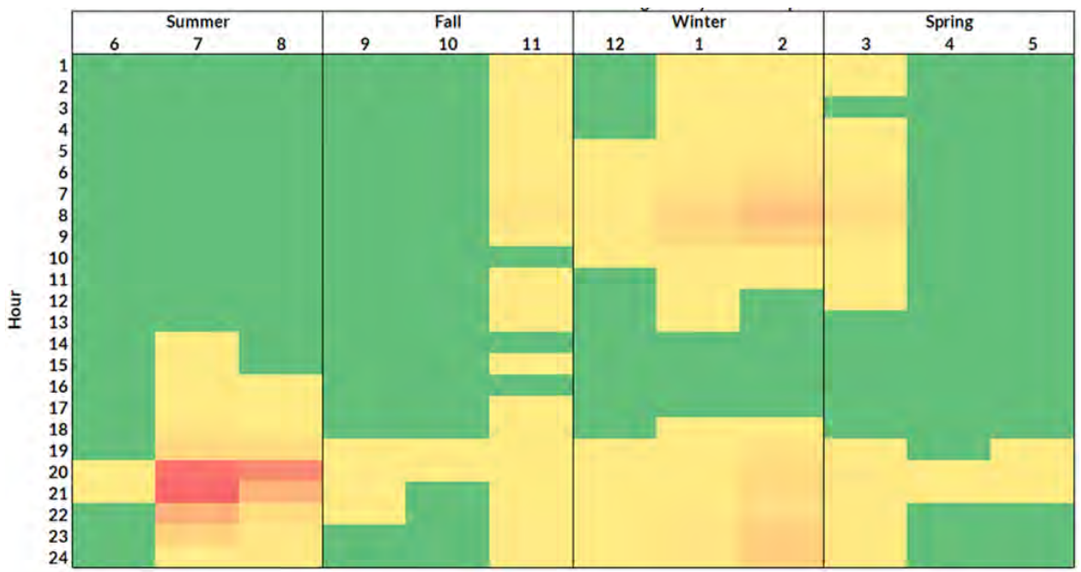
*Provides the 2024 ProbA Results for Comparison

**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.




**2027-2028 ProbA Heat Map**




**2029-2030 ProbA Heat Map**

**Demand**

LSEs within MISO's footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the *2025 LTRA*, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO's normal process, the coincident peak demand forecast is used to determine each LSE's PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the *2024 LTRA*, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published a *Long-Term Load Forecast* white paper in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

**Demand-Side Management**

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO's latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

**Distributed Energy Resources**

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO's transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

**Generation**

Because of the size of MISO's interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent 2025 OMS-MISO survey used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA's existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

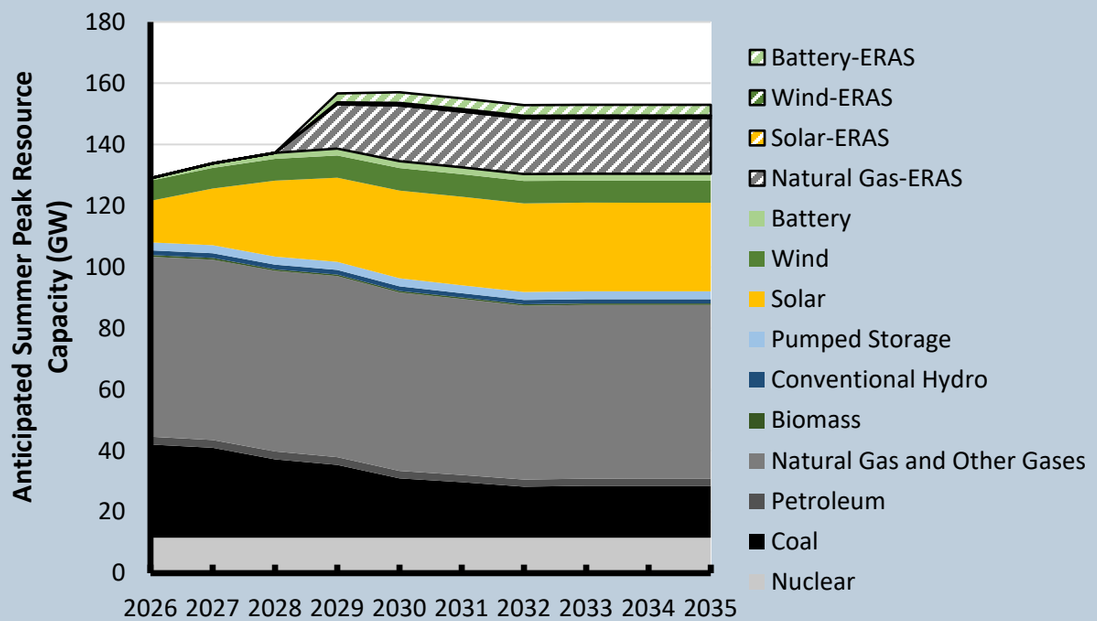
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

MISO's accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

**Energy Storage**

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO's anticipated installations include an addition of more than 2.4 GW by Summer 2030 and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO's growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from the ERAS program is expected to grow to over 20 GW by Summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA* and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.




**The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity**

**Energy Transfers**
In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO's probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

**Transmission**
MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO's transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO's transmission expansion plan, see information and reports posted on MISO's MTEP page.

MISO has 488 transmission projects totaling $30 billion planned across MTEP24, its Long Range Transmission Planning (LRTP) Tranche 2.1, and the SPP-MISO Joint Targeted Interconnection Queue (JTIQ). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area's large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO's Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

**Reliability Issues**
Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

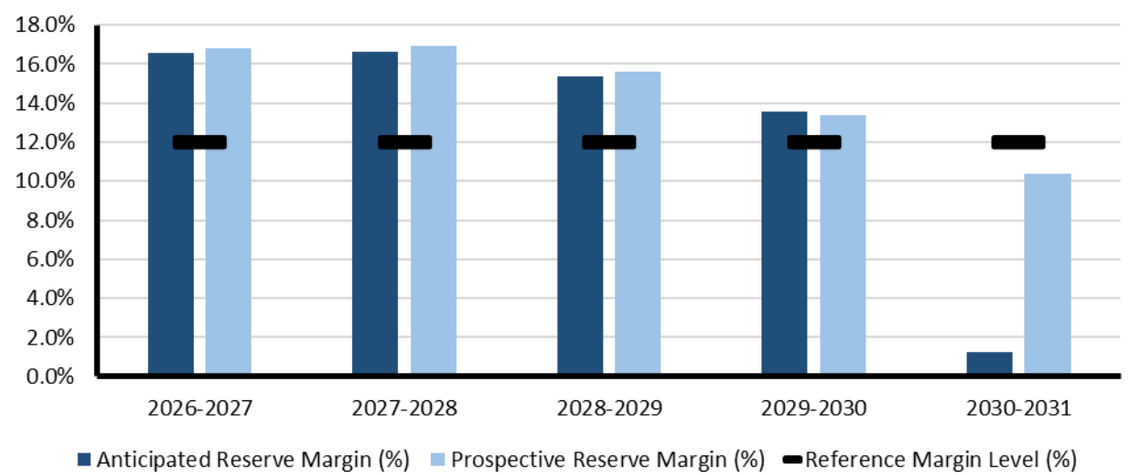


# MRO-Manitoba Hydro

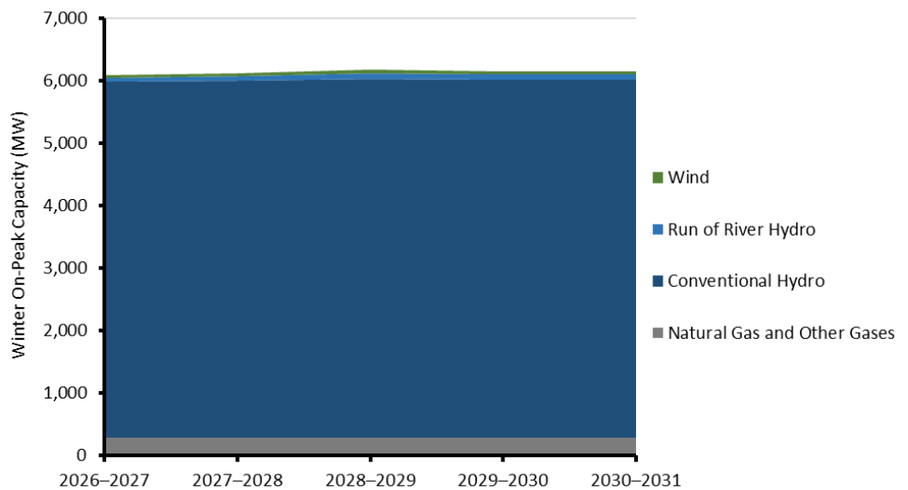
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 5,002 | 5,041 | 5,081 | 5,137 | 5,374 | 5,412 | 5,447 | 5,507 | 5,580 | 5,655 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Internal Demand | 5,002 | 5,041 | 5,081 | 5,137 | 5,374 | 5,412 | 5,447 | 5,507 | 5,580 | 5,655 |
| Additions: Tier 1 | 36 | 50 | 63 | 63 | 63 | 63 | 63 | 63 | 63 | 63 |
| Additions: Tier 2 | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 500 | 500 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | -113 | -93 | -167 | -172 | -565 | -565 | -565 | -565 | -565 | -315 |
| Existing-Certain and Net Firm Transfers | 5,794 | 5,831 | 5,799 | 5,770 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,627 |
| Anticipated Reserve Margin (%) | 16.6% | 16.7% | 15.4% | 13.6% | 1.2% | 0.5% | -0.1% | -1.2% | -2.5% | 0.6% |
| Prospective Reserve Margin (%) | 16.8% | 16.9% | 15.6% | 13.4% | 10.4% | 9.6% | 8.9% | 7.7% | 6.3% | 9.3% |
| Reference Margin Level (%) | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.[36]

| MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026–2027** | **2027–2028** | **2028–2029** | **2029–2030** | **2030–2031** |
| Natural Gas | 278 | 278 | 278 | 278 | 278 |
| Wind | 52 | 52 | 52 | 52 | 52 |
| **Conventional Hydro** | 5,705 | 5,723 | 5,758 | 5,735 | 5,735 |
| Run of River Hydro | 59 | 71 | 90 | 90 | 90 |
| **Total MW** | **6,094** | **6,124** | **6,179** | **6,155** | **6,155** |

[36] Province directs Manitoba Hydro to continue pause on new cryptocurrency connections

## MRO-Manitoba Hydro Assessment

**Planning Reserve Margins**
The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts ("diversity capacity") in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

**Demand**
Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

**Demand-Side Management**
Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba's winter peak. The pilot program is targeting to launch for the winter of 2025.

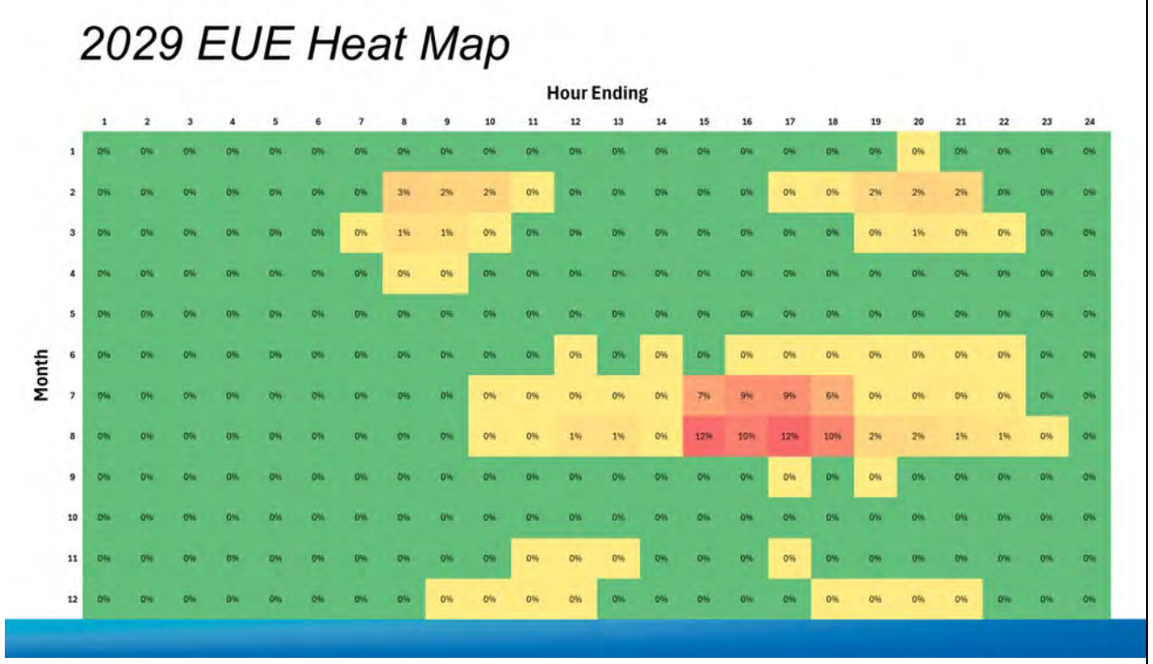
**Energy Risk**
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

**Probabilistic Assessment (ProbA)**
Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

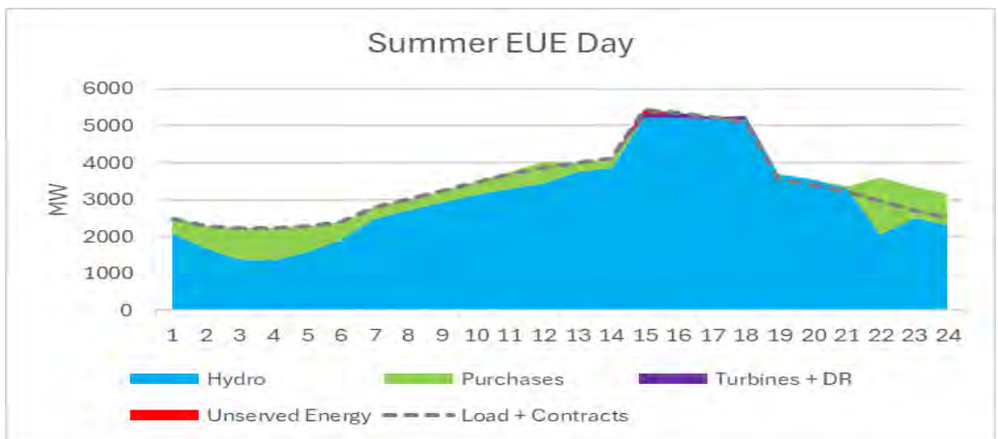
| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 4 | 3 | 6 |
| NEUE (ppm) | 0.17 | 0.12 | 0.23 |
| LOLH (hours per Year) | 0.05 | 0.03 | 0.06 |
| * Provides the 2024 ProbA Results for Comparison | | | |

There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.




A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.




**Distributed Energy Resources**

There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DERs may be dependent on solar PV subsidies and/or incentives.

**Generation**

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an Integrated Resource Plan that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba's electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro's forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

**Energy Storage**

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

**Energy Transfers**

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts ("diversity capacity") in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

**Transmission**

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

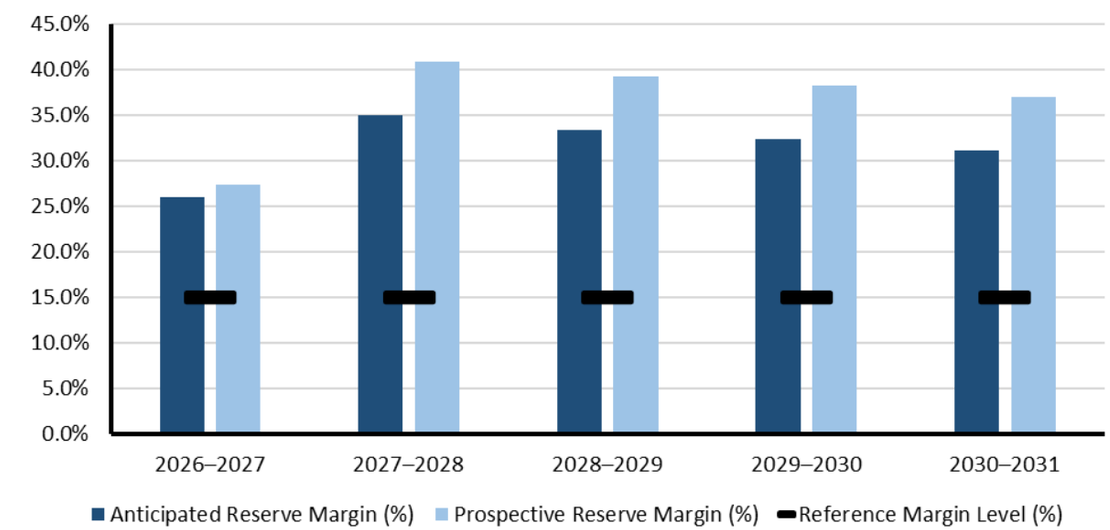


# MRO-SaskPower

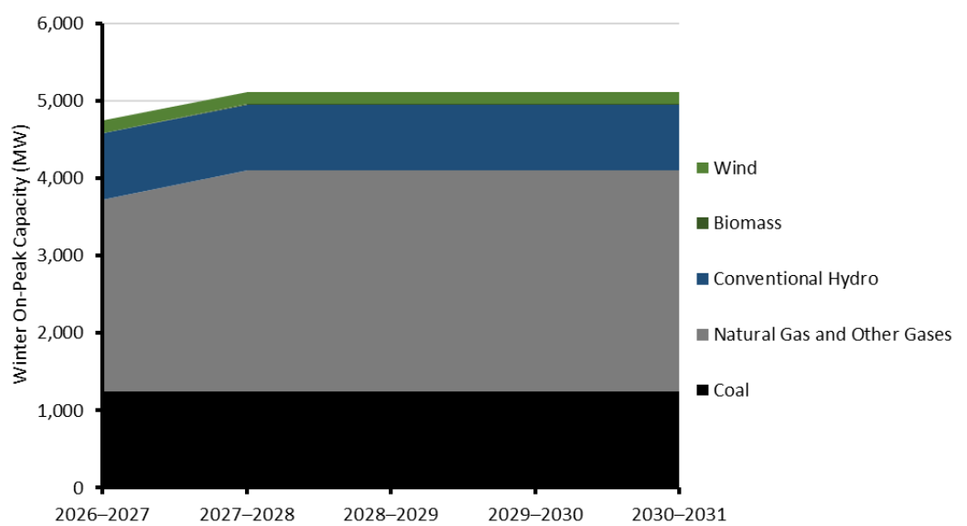
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 4,040 | 4,112 | 4,148 | 4,180 | 4,205 | 4,230 | 4,278 | 4,314 | 4,347 | 4,375 |
| Demand Response | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 | 72 |
| Net Internal Demand | 3,968 | 4,040 | 4,076 | 4,108 | 4,133 | 4,158 | 4,206 | 4,242 | 4,275 | 4,303 |
| Additions: Tier 1 | 90 | 460 | 460 | 460 | 460 | 460 | 460 | 460 | 460 | 460 |
| Additions: Tier 2 | 55 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 | 241 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | 290 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 |
| Existing-Certain and Net Firm Transfers | 4,907 | 4,992 | 4,976 | 4,976 | 4,961 | 4,962 | 4,900 | 4,962 | 4,976 | 4,892 |
| Anticipated Reserve Margin (%) | 25.9% | 35.0% | 33.4% | 32.3% | 31.2% | 30.4% | 27.4% | 27.8% | 27.2% | 24.4% |
| Prospective Reserve Margin (%) | 27.3% | 40.9% | 39.3% | 38.2% | 37.0% | 35.5% | 32.5% | 32.8% | 32.1% | 29.2% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower's recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan's average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower's forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower's primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan's power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan's gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

| MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 |
| Coal | 1,249 | 1,249 | 1,249 | 1,249 | 1,249 |
| Natural Gas | 2,480 | 2,850 | 2,850 | 2,850 | 2,850 |
| Biomass | 3 | 3 | 3 | 3 | 3 |
| Wind | 164 | 162 | 162 | 162 | 162 |
| Conventional Hydro | 856 | 856 | 856 | 856 | 856 |
| Other | 17 | 17 | 1 | 1 | 1 |
| **Total MW** | **4,769** | **5,137** | **5,121** | **5,121** | **5,121** |

## MRO-SaskPower Assessment

**Planning Reserve Margins**

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

**Energy Assessment, Including Non-Peak Hour Risk**

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

**ProbA Results**

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

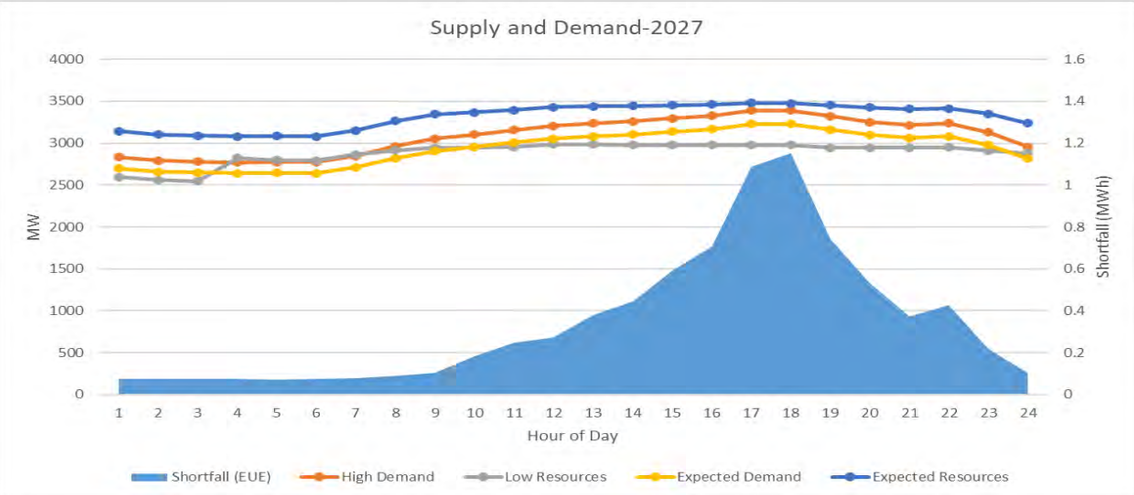
| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 75 | 145 | 5 |
| NEUE (ppm) | 2.807 | 5.242 | 0.190 |
| LOLH (hours per Year) | 0.547 | 1.094 | 0.046 |
| *** Provides the 2024 ProbA Results for Comparison** | | | |

The annual EUE heat map for 2027 is provided below.

**Hourly EUE Heat Map : 2027**

| EUE | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Feb-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 0% | 0% | 0% |
| Mar-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Apr-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| May-27 | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 2% | 2% | 3% | 3% | 3% | 3% | 4% | 5% | 5% | 3% | 3% | 2% | 3% | 2% | 1% |
| Jun-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Jul-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Aug-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 1% | 1% | 2% | 2% | 1% | 1% | 1% | 1% | 0% | 0% |
| Sep-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 0% | 0% | 0% |
| Oct-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 1% | 1% | 1% | 0% | 0% | 0% |
| Nov-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Dec-27 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.




**Demand**

Saskatchewan experiences its peak season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the *2024 LTRA*'s projection of 1.35% average annual peak demand growth.

**Demand-Side Management**

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours' notification, but those loads are not included in PRM calculations.

**Distributed Energy Resources**

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

**Generation**

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province's future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

**Energy Storage**

SaskPower's first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

**Energy Transfers**

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower's emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

**Transmission**

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower's Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan's remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

**Reliability Issues**

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan's power generation and natural gas production. Saskatchewan's pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

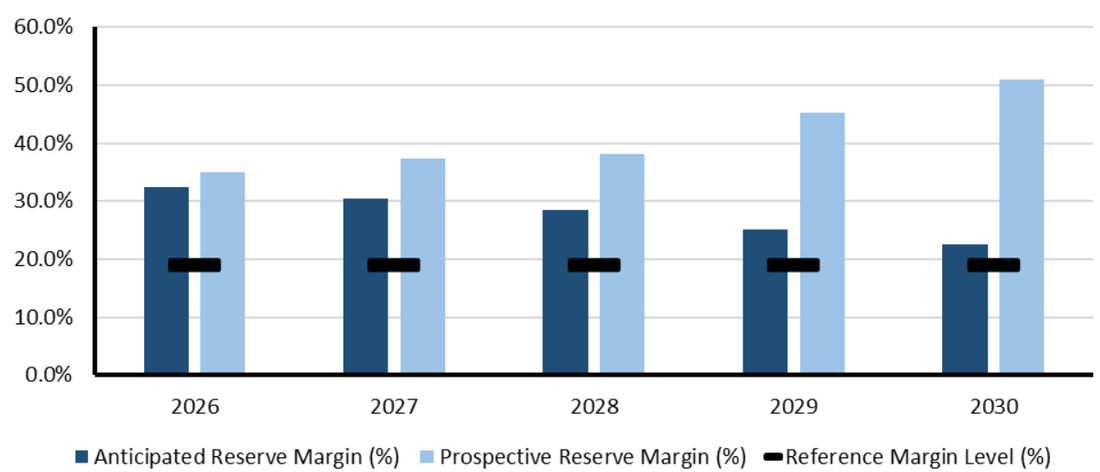


# MRO-SPP

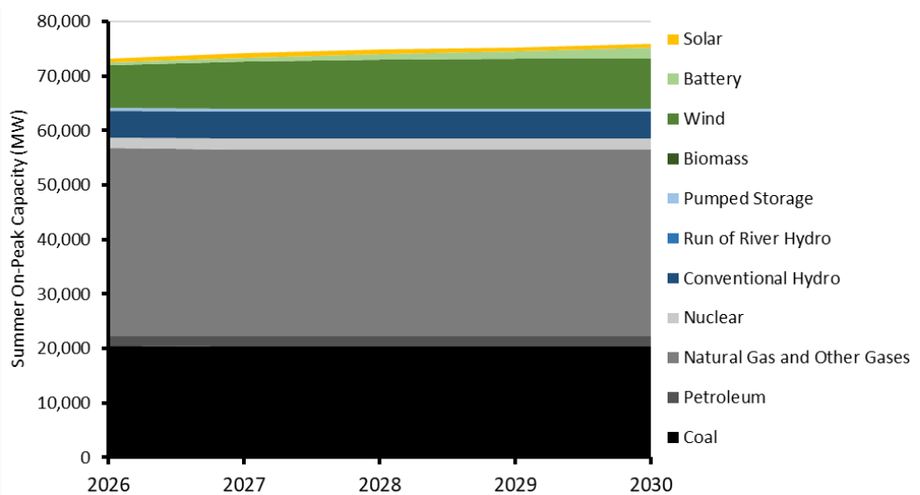
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 57,479 | 59,121 | 60,689 | 62,766 | 64,475 | 66,283 | 66,982 | 67,570 | 68,049 | 68,622 |
| Demand Response | 2,138 | 2,162 | 2,332 | 2,508 | 2,509 | 2,511 | 2,513 | 2,514 | 2,718 | 2,720 |
| Net Internal Demand | 55,340 | 56,959 | 58,357 | 60,258 | 61,966 | 63,772 | 64,469 | 65,056 | 65,331 | 65,902 |
| Additions: Tier 1 | 1,808 | 3,020 | 3,685 | 4,251 | 4,815 | 4,866 | 5,344 | 5,344 | 5,344 | 5,344 |
| Additions: Tier 2 | 2,436 | 6,104 | 8,948 | 15,659 | 21,487 | 23,345 | 25,664 | 27,277 | 27,877 | 28,627 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | -18 | -78 | -78 | -78 | -78 | -79 | -79 | -79 | -79 | -79 |
| Existing-Certain and Net Firm Transfers | 71,475 | 71,224 | 71,232 | 71,127 | 71,146 | 71,115 | 71,135 | 71,106 | 71,105 | 71,106 |
| Anticipated Reserve Margin (%) | 32.4% | 30.3% | 28.4% | 25.1% | 22.6% | 19.1% | 18.6% | 17.5% | 17.0% | 16.0% |
| Prospective Reserve Margin (%) | 34.9% | 37.3% | 38.2% | 45.2% | 50.9% | 48.7% | 51.5% | 51.8% | 51.8% | 50.6% |
| Reference Margin Level (%) | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% | 19.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

| MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 20,473 | 20,440 | 20,440 | 20,428 | 20,428 |
| Coal* | 19,187 | 19,154 | 18,086 | 18,075 | 18,075 |
| Petroleum | 1,824 | 1,827 | 1,827 | 1,827 | 1,829 |
| Petroleum* | 1,824 | 1,771 | 1,771 | 1,771 | 1,774 |
| Natural Gas | 34,525 | 34,303 | 34,303 | 34,265 | 34,265 |
| Natural Gas* | 34,363 | 33,662 | 33,550 | 33,512 | 33,268 |
| Biomass | 35 | 35 | 35 | 35 | 35 |
| Solar | 700 | 700 | 700 | 700 | 700 |
| Wind | 7,831 | 8,581 | 9,044 | 9,134 | 9,191 |
| Conventional Hydro | 4,925 | 4,993 | 5,009 | 5,026 | 5,030 |
| Pumped Storage | 456 | 456 | 456 | 415 | 460 |
| Nuclear | 1,945 | 1,945 | 1,945 | 1,945 | 1,945 |
| Other | 281 | 281 | 281 | 281 | 281 |
| Battery | 379 | 833 | 1,027 | 1,472 | 1,949 |
| Total MW | 73,429 | 74,450 | 75,123 | 75,584 | 76,168 |
| **Total MW*** | 71,981 | 72,467 | 71,960 | 72,422 | 72,762 |
| ***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked. | | | | | |

**Planning Reserve Margins**

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the *2025 LTRA* as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP's 2023 LOLE study supported much of the demand forecast presented in NERC's *2024 LTRA* and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO's Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

**ProbA Results**

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP's LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP's LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 0 | 0 | 0 |
| NEUE (ppm) | 0.00 | 0.00 | 0.00 |
| LOLH (hours per Year) | 0.00 | 0.00 | 0.00 |
| ***Provides the 2024 ProbA Results for Comparison** | | | |

**Demand**

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP's energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

**Demand-Side Management**
SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP's tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

**Distributed Energy Resources**
The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

**Generation**
In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the *2024 LTRA*, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP's Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP's Tier 2 queue since July and are not reflected in this year's LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC's reliability assessments and ProbA and count toward ARM.

**Energy Storage**
There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

**Capacity Transfers**
Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

**Transmission**
SPP's 2024 Integrated Transmission Plan (ITP) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

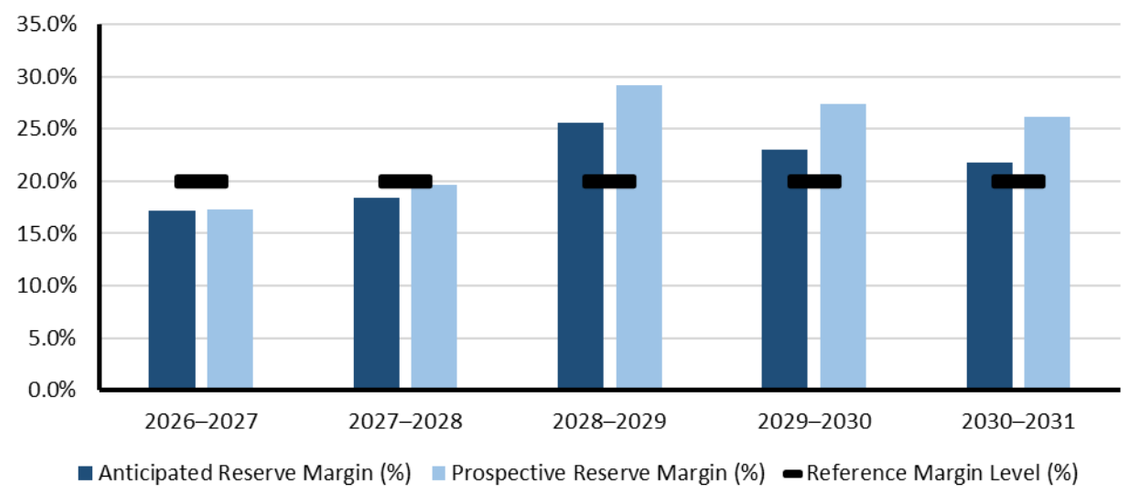


# NPCC-Maritimes

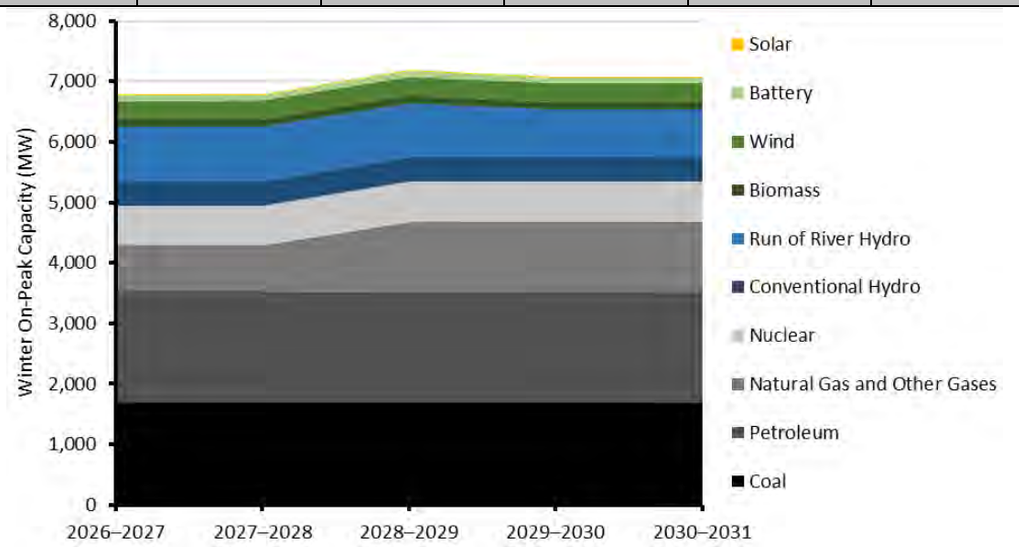
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 6,107 | 6,157 | 6,194 | 6,231 | 6,292 | 6,346 | 6,380 | 6,493 | 6,579 | 6,669 |
| Demand Response | 264 | 283 | 290 | 291 | 290 | 291 | 290 | 291 | 290 | 290 |
| Net Internal Demand | 5,843 | 5,875 | 5,904 | 5,940 | 6,001 | 6,055 | 6,089 | 6,202 | 6,289 | 6,380 |
| Additions: Tier 1 | 173 | 179 | 579 | 579 | 579 | 579 | 579 | 579 | 579 | 579 |
| Additions: Tier 2 | 6 | 367 | 656 | 1,492 | 1,492 | 1,492 | 1,492 | 1,492 | 1,492 | 1,492 |
| Additions: Tier 3 | 0 | 0 | 23 | 101 | 215 | 227 | 239 | 251 | 260 | 260 |
| Net Firm Capacity Transfers | -32 | 75 | 145 | 145 | 145 | 145 | 145 | 145 | 145 | 145 |
| Existing-Certain and Net Firm Transfers | 6,673 | 6,780 | 6,838 | 6,727 | 6,727 | 6,727 | 6,621 | 6,621 | 6,596 | 6,707 |
| Anticipated Reserve Margin (%) | 17.2% | 18.5% | 25.6% | 23.0% | 21.7% | 20.7% | 18.2% | 16.1% | 14.1% | 14.2% |
| Prospective Reserve Margin (%) | 17.3% | 19.6% | 29.2% | 27.4% | 26.1% | 25.0% | 22.6% | 20.3% | 18.3% | 18.3% |
| Reference Margin Level (%) | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## NPCC-Maritimes Highlights

- Since the *2024 LTRA*, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year's projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

| NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026–2027** | **2027–2028** | **2028–2029** | **2029–2030** | **2030–2031** |
| Coal | 1,696 | 1,696 | 1,696 | 1,696 | 1,696 |
| Coal* | 1,696 | 1,696 | 1,410 | 1,003 | 691 |
| Petroleum | 1,831 | 1,831 | 1,820 | 1,820 | 1,820 |
| Natural Gas | 757 | 757 | 1,157 | 1,157 | 1,157 |
| Biomass | 129 | 129 | 129 | 129 | 129 |
| Solar | 10 | 10 | 10 | 10 | 10 |
| Wind | 300 | 306 | 306 | 306 | 306 |
| Conventional Hydro | 395 | 395 | 395 | 395 | 395 |
| Run of River Hydro | 901 | 901 | 901 | 790 | 790 |
| Nuclear | 663 | 663 | 671 | 671 | 671 |
| Other | 98 | 98 | 89 | 89 | 89 |
| Battery | 99 | 99 | 99 | 99 | 99 |
| Total MW | 6,878 | 6,884 | 7,272 | 7,161 | 7,161 |
| Total MW* | 6,878 | 6,884 | 6,986 | 6,468 | 6,156 |
| *** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked. | | | | | |

## NPCC-Maritimes Assessment

**Planning Reserve Margins**

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two BAs within the Maritimes area, as members of the NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

**Energy Risk**

During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy, needs and hence there are no constraints with converting the capacity to energy during these times.

The two Balancing Authorities within the Maritimes Area as members of the Northeast Power Coordinating Council (NPCC) jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual and seasonal ProbAs, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

**ProbA**

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | **5** | **15** | **7** |
| NEUE (ppm) | **0.17** | **0.52** | **0.25** |
| LOLH (hours/year) | **0.09** | **0.25** | **0.10** |
| *Results from the 2024 ProbA simulations | | | |

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

**Demand**

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the *2024 LTRA*, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

**Demand-Side Management**

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW. [37] The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

**Distributed Energy Resources**

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

**Generation**

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program (2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026-2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029-2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

**Energy Storage**

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the *2025 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

[37] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

**Capacity Transfers**
Probabilistic studies show that Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

**Transmission**
NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

**Reliability Issues**
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



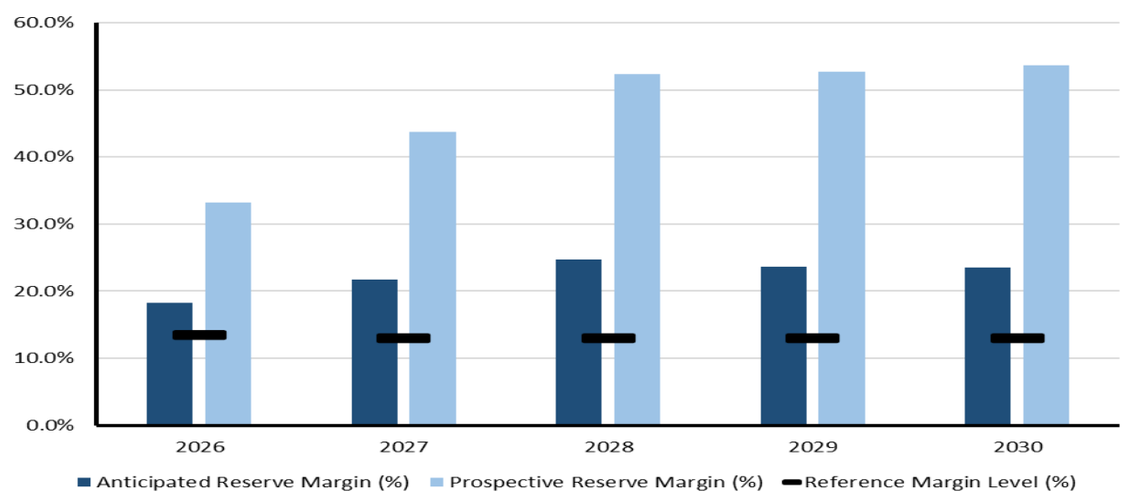
# NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

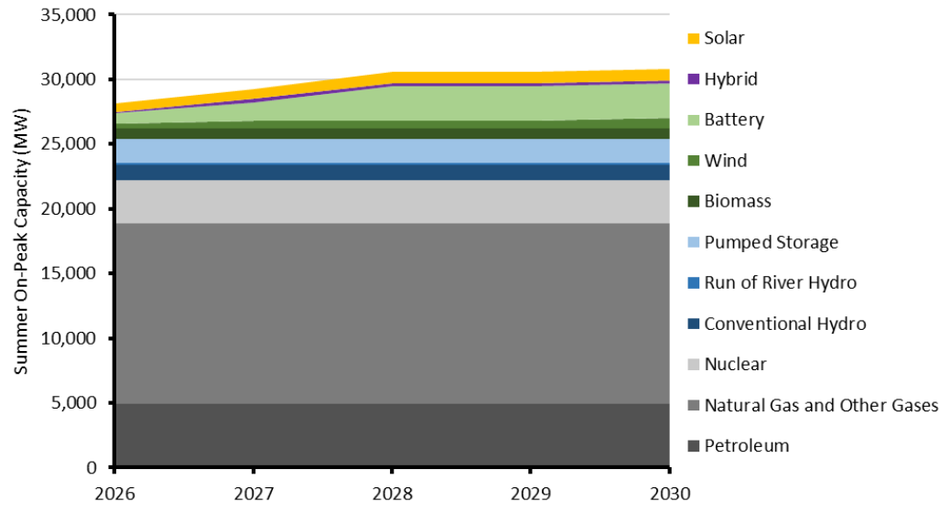
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 24,877 | 24,945 | 25,124 | 25,347 | 25,557 | 25,821 | 26,123 | 26,486 | 26,897 | 27,331 |
| Demand Response | 623 | 544 | 544 | 544 | 544 | 544 | 544 | 544 | 544 | 544 |
| Net Internal Demand | 24,254 | 24,401 | 24,580 | 24,803 | 25,013 | 25,277 | 25,579 | 25,942 | 26,353 | 26,787 |
| Additions: Tier 1 | 1,081 | 2,183 | 3,543 | 3,551 | 3,781 | 3,781 | 3,913 | 3,913 | 4,263 | 4,263 |
| Additions: Tier 2 | 1,113 | 2,871 | 4,274 | 4,687 | 5,037 | 5,037 | 5,037 | 5,387 | 5,387 | 5,387 |
| Additions: Tier 3 | 872 | 4,129 | 10,335 | 11,426 | 11,830 | 12,924 | 12,924 | 12,924 | 12,924 | 12,924 |
| Net Firm Capacity Transfers | 567 | 465 | 84 | 84 | 84 | 84 | 84 | 0 | 0 | 0 |
| Existing-Certain and Net Firm Transfers | 27,607 | 27,505 | 27,124 | 27,124 | 27,124 | 27,124 | 27,124 | 27,040 | 27,040 | 27,040 |
| Anticipated Reserve Margin (%) | 18.3% | 21.7% | 24.8% | 23.7% | 23.6% | 22.3% | 21.3% | 19.3% | 18.8% | 16.9% |
| Prospective Reserve Margin (%) | 33.2% | 43.7% | 52.3% | 52.7% | 53.7% | 52.1% | 50.8% | 49.7% | 48.7% | 46.3% |
| Reference Margin Level (%) | 13.4% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the New England Clean Energy Connect) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

| NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[38] | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Petroleum | 4,899 | 4,899 | 4,899 | 4,899 | 4,899 |
| Natural Gas | 13,939 | 13,939 | 13,939 | 13,939 | 13,939 |
| Biomass | 776 | 776 | 776 | 776 | 776 |
| Solar | 645 | 726 | 864 | 872 | 872 |
| Wind | 416 | 622 | 622 | 622 | 852 |
| Conventional Hydro | 1,165 | 1,165 | 1,165 | 1,165 | 1,165 |
| Run of River Hydro | 179 | 179 | 179 | 179 | 179 |
| Pumped Storage | 1,864 | 1,864 | 1,864 | 1,864 | 1,864 |
| Nuclear | 3,351 | 3,351 | 3,351 | 3,351 | 3,351 |
| Hybrid | 96 | 287 | 287 | 287 | 287 |
| Battery | 791 | 1,416 | 2,638 | 2,638 | 2,638 |
| Total MW | 28,121 | 29,223 | 30,584 | 30,591 | 30,821 |

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

[38] MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

## NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

**Planning Reserve Margins**

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet NPCC's resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

**Energy Risks (Including Non-Peak Hour Risk)**

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.
- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

**Probabilistic Assessments (ProbA and Other Studies)**

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states' policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

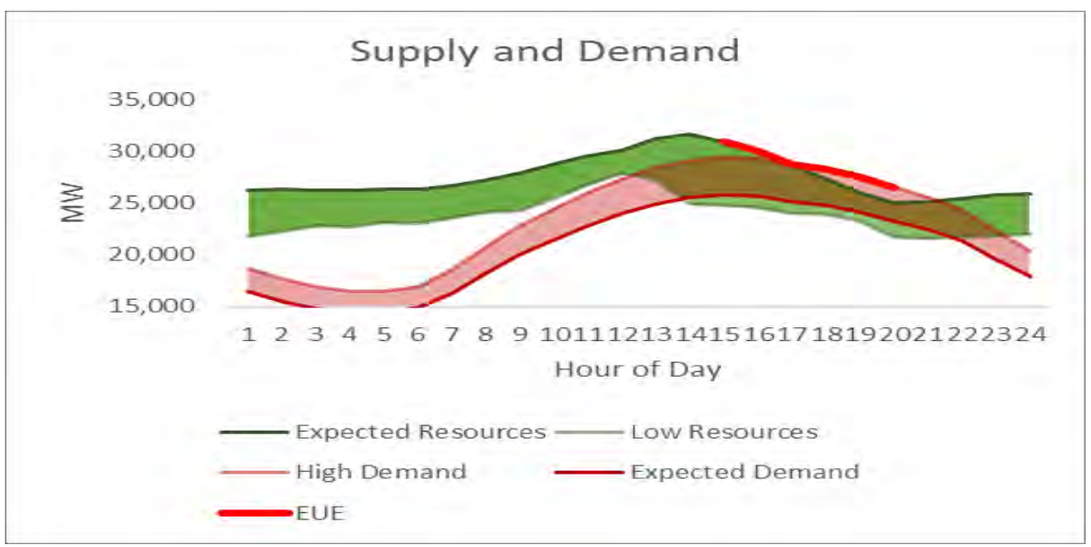
| NPCC New England Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 10.7 | 0.1 | 1.8 |
| NEUE (ppm) | 0.1 | 0.0 | 0.0 |
| LOLH (hours per Year) | 0.1 | 0.0 | <0.1 |
| * Provides the 2024 ProbA results for Comparison | | | |

**EUE Heat Map – 2029**

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

| Month \ Hour | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 10% | 33% | 24% | 1% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 5% | 19% | 5% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.




**Demand**

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the *2024 LTRA*. The energy growth projection has decreased as well since the *2024 LTRA*.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

**Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)**

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new Planning Procedure 12 entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

**Generation**

The two largest changes that will impact New England's generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the Capacity Auction Reforms Key Project.

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

**Energy Storage**

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

**Capacity Transfers (Reliance on Assistance)**

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the *2025 LTRA* Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

**Transmission**

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE's longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

**Reliability Issues**

New England's power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected "in-service" dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- Capacity Auction Reforms
- Operational Impacts of Extreme Weather Events
- Day-Ahead Ancillary Services Initiative
- 2024 Economic Study
- Extended-Term Transmission Planning Tariff Changes (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- Longer-Term Transmission Studies
- Storage As Transmission Only Asset
- FERC Order No. 1920 Project
- FERC Order No. 2023 Project
- FERC Order No. 2222 Project

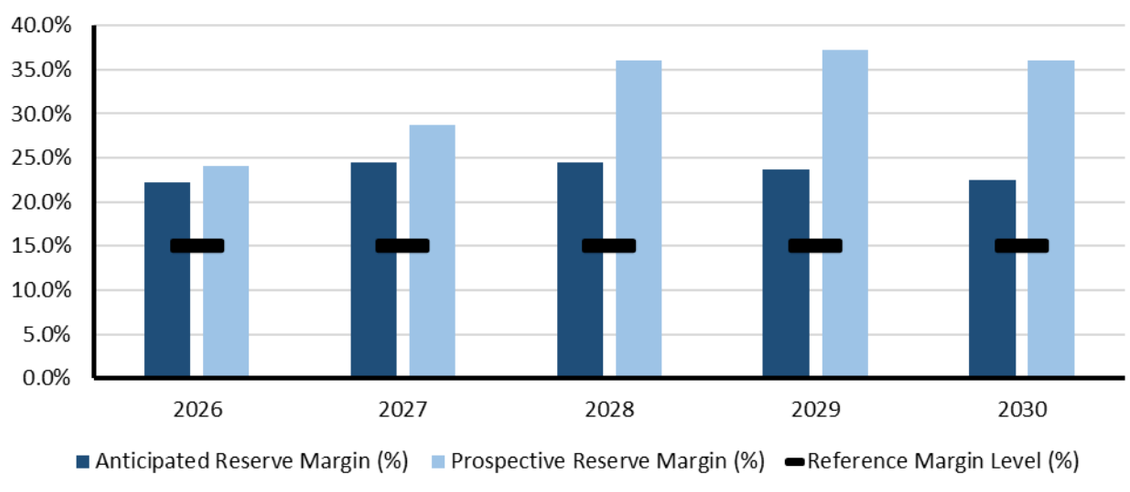


# NPCC-New York

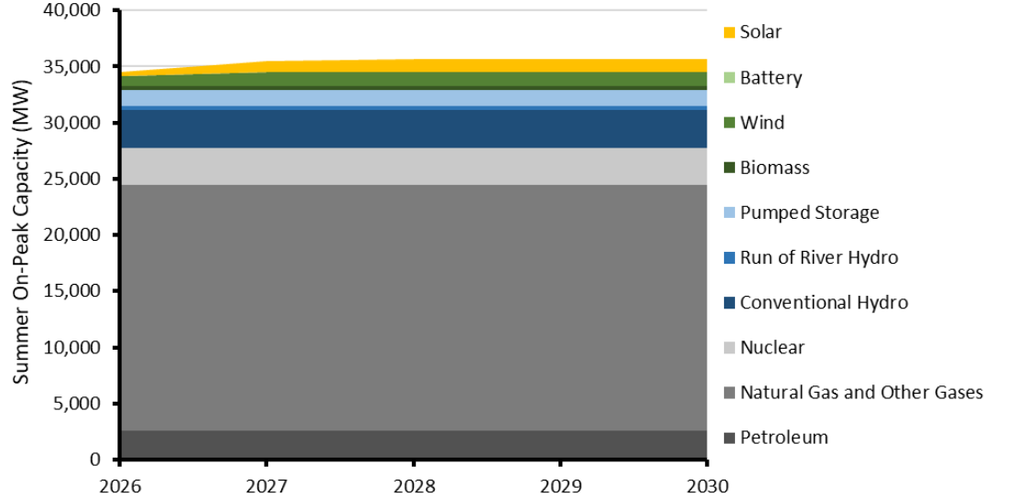
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 31,990 | 32,280 | 32,410 | 32,620 | 32,910 | 33,190 | 33,520 | 33,870 | 34,170 | 34,500 |
| Demand Response | 989 | 989 | 989 | 989 | 989 | 989 | 989 | 989 | 989 | 989 |
| Net Internal Demand | 31,001 | 31,291 | 31,421 | 31,631 | 31,921 | 32,201 | 32,531 | 32,881 | 33,181 | 33,511 |
| Additions: Tier 1 | 532 | 1,509 | 1,660 | 1,660 | 1,660 | 1,660 | 1,660 | 1,660 | 1,660 | 1,660 |
| Additions: Tier 2 | 574 | 1,317 | 3,642 | 4,313 | 4,313 | 4,313 | 4,313 | 4,313 | 4,313 | 4,313 |
| Additions: Tier 3 | 150 | 1,516 | 9,280 | 19,034 | 25,847 | 28,035 | 28,035 | 28,526 | 29,009 | 29,009 |
| Net Firm Capacity Transfers | 3,405 | 3,486 | 3,486 | 3,486 | 3,486 | 3,486 | 3,486 | 3,486 | 3,486 | 3,486 |
| Existing-Certain and Net Firm Transfers | 37,368 | 37,449 | 37,450 | 37,450 | 37,450 | 36,995 | 36,995 | 36,995 | 36,995 | 36,995 |
| Anticipated Reserve Margin (%) | 22.3% | 24.5% | 24.5% | 23.6% | 22.5% | 20.0% | 18.8% | 17.6% | 16.5% | 15.4% |
| Prospective Reserve Margin (%) | 24.1% | 28.7% | 36.1% | 37.3% | 36.0% | 33.4% | 32.1% | 30.7% | 29.5% | 28.2% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO's *2025 Quarter 3 Short-Term Assessment of Reliability* (STAR)[39] report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

| NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Petroleum | 2,597 | 2,597 | 2,597 | 2,597 | 2,597 |
| Natural Gas | 21,858 | 21,858 | 21,858 | 21,858 | 21,858 |
| Biomass | 334 | 334 | 334 | 334 | 334 |
| Solar | 345 | 931 | 1,083 | 1,083 | 1,083 |
| Wind | 850 | 1,221 | 1,221 | 1,221 | 1,221 |
| Geothermal | 0 | 0 | 0 | 0 | 0 |
| Conventional Hydro | 3,324 | 3,324 | 3,324 | 3,324 | 3,324 |
| Run of River Hydro | 418 | 418 | 418 | 418 | 418 |
| Pumped Storage | 1,411 | 1,411 | 1,411 | 1,411 | 1,411 |
| Nuclear | 3,326 | 3,326 | 3,326 | 3,326 | 3,326 |
| Hybrid | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 |
| Battery | 32 | 52 | 52 | 52 | 52 |
| Unknown | 0 | 0 | 0 | 0 | 0 |
| Total MW | 34,495 | 35,472 | 35,623 | 35,623 | 35,623 |

[39] NYISO's *2025 Q3 STAR Report*: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf; Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

## NPCC-New York Assessment

**Planning Reserve Margins**

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2024 Reliability Needs Assessment*[40] found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC's resource adequacy criterion of "one day in 10 years." The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

**Energy Assessment, Including Non-Peak Hour Risk**

New York State's Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

**Probabilistic Assessments (NERC ProbA and Other Studies)**

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

**ProbA Results**

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

[40] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

| NPCC New York Base-Case Summary of Results | | | |
|---|---|---|---|
| | 2026* | 2027 | 2029 |
| EUE (MWh) | 1.909 | 0.466 | 12.478 |
| NEUE (ppm) | 0.012 | 0.003 | 0.078 |
| LOLH (hours per Year) | 0.011 | 0.002 | 0.035 |
| * Provides the 2024 ProbA results for Comparison | | | |

**EUE Heat Maps – 2029**

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

| Month \ Hour | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 7% | 24% | 25% | 7% | 3% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 8% | 16% | 6% | 1% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.




Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

**Demand**

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as electric vehicle charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year's forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

**Demand-Side Management**

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

**Distributed Energy Resources**

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

**Generation**

Significant new resource development will be required to achieve New York's energy targets under the CLCPA. According to the 2023–2042 System and Resource Outlook the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO's interconnection process[41] contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York's public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation.

On June 23, 2025,[42] New York's governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

**Energy Storage**

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is preparing the implementation of a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resource models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

**Capacity Transfers**

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

[41] https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

[42] https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

**Transmission**

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison's proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

**Reliability Issues**

NYISO's *2024 Reliability Needs Assessment*[43] (RNA) and subsequent analysis[44] identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO's 2025 Quarter 3 STAR report[45] identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

[43] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf
[44] https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
[45] NYISO's 2025 Q3 STAR Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf and Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

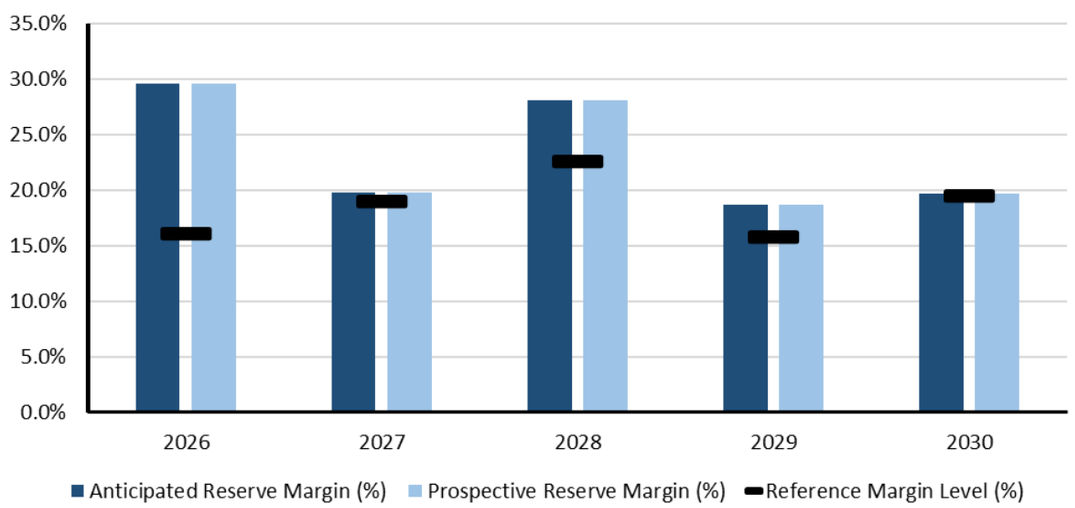


# NPCC-Ontario

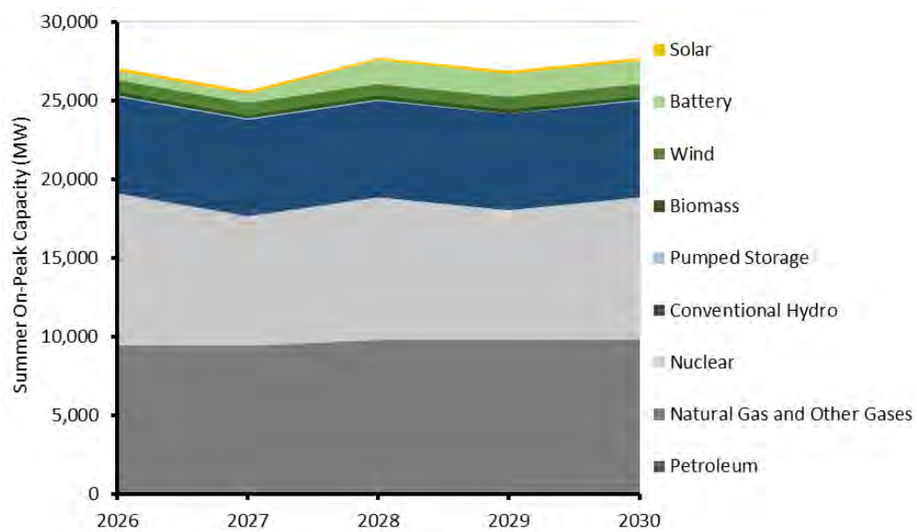
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 23,403 | 24,023 | 24,514 | 25,587 | 26,443 | 26,927 | 27,747 | 28,621 | 29,202 | 29,974 |
| Demand Response | 2,046 | 1,998 | 2,090 | 2,092 | 2,093 | 2,095 | 2,096 | 2,098 | 2,099 | 2,101 |
| Net Internal Demand | 21,357 | 22,025 | 22,424 | 23,495 | 24,350 | 24,832 | 25,651 | 26,523 | 27,103 | 27,873 |
| Additions: Tier 1 | 853 | 853 | 2,156 | 2,156 | 2,156 | 2,964 | 3,507 | 4,051 | 4,579 | 5,387 |
| Additions: Tier 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 600 | 600 | 600 | 1,233 | 1,324 | 1,324 |
| Net Firm Capacity Transfers | 602 | 772 | 1,002 | 1,002 | 1,432 | 1,002 | 302 | 302 | 302 | 302 |
| Existing-Certain and Net Firm Transfers | 26,833 | 25,541 | 26,577 | 25,737 | 26,999 | 25,623 | 25,767 | 25,767 | 26,611 | 26,611 |
| Anticipated Reserve Margin (%) | 29.6% | 19.8% | 28.1% | 18.7% | 19.7% | 15.1% | 14.1% | 12.4% | 15.1% | 14.8% |
| Prospective Reserve Margin (%) | 29.6% | 19.8% | 28.1% | 18.7% | 19.7% | 15.1% | 14.1% | 12.4% | 15.1% | 14.8% |
| Reference Margin Level (%) | 16.1% | 19.0% | 22.6% | 15.8% | 19.5% | 13.9% | 14.7% | 9.6% | 14.3% | 13.2% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## NPCC-Ontario Highlights

- Ontario's ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario's 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year's LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO's reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

| NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Petroleum | 3 | 3 | 3 | 3 | 3 |
| Natural Gas | 9,385 | 9,385 | 9,790 | 9,790 | 9,790 |
| Biomass | 299 | 304 | 310 | 310 | 310 |
| Solar | 150 | 150 | 150 | 150 | 150 |
| Wind | 724 | 725 | 728 | 732 | 732 |
| Conventional Hydro | 6,163 | 6,163 | 6,163 | 6,163 | 6,163 |
| Pumped Storage | 38 | 38 | 38 | 38 | 38 |
| Nuclear | 9,724 | 8,256 | 9,059 | 8,214 | 9,047 |
| Battery | 597 | 597 | 1,489 | 1,489 | 1,489 |
| Total MW | 27,084 | 25,622 | 27,731 | 26,891 | 27,723 |

## NPCC-Ontario Assessment

**Planning Reserve Margins**

Ontario's ARMs remain above the RML for the first five years of the *2025 LTRA* outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year's publication.

The IESO calculates Ontario's reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 Annual Planning Outlook (APO) includes reserves of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the *2025 LTRA*, the IESO applied NERC's definitions for Tier 1 and Tier 3 resources. The IESO's Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It's important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The *2025 LTRA* assesses reliability independent of contractual status, unlike the 2025 APO, which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the *2025 LTRA* outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The RAF remains unchanged since the *2024 LTRA* and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**

Ontario conducts annual energy adequacy assessments using Energy Exemplar's Plexos software, which models the province's nodal transmission network and simulates dispatch under expected system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA's purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the Reliability Outlook (RO), which evaluates energy adequacy over an 18-month horizon. These assessments use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as capacity auctions, coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario's energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 0.043 | 0.001 | 0.066 |
| NEUE (ppm) | 0.000 | 0.000 | 0.000 |
| LOLH (hours per Year) | 0.000 | 0.000 | 0.000 |
| ***Provides the 2024 ProbA Results for Comparison** | | | |

**Demand**

Ontario's demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the *2024 LTRA* were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO's demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts System Impact Assessments (SIA) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

**Demand-Side Management**

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the *2024 LTRA*, the Peak Perks program has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the Industrial Conservation Initiative (ICI), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a $1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

**Distributed Energy Resources**

Ontario's DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the Enabling Resources Program (ERP), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO's DER Potential Study and Local Generation Program aim to further integrate DERs into Ontario's RAF.

**Generation**

Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO's Market Renewal's Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario's long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO's second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario's adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario's generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

**Energy Storage**

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario's ability to manage variability and meet ramping needs.

**Capacity Transfers**

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The 2016 agreement allows for a 500 MW swap, while the 2024 agreement enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario's planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario's transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO's internal studies.

**Transmission**

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a Transmitter Selection Framework (TSF) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

**Reliability Issues**

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario's gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO's Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario's planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

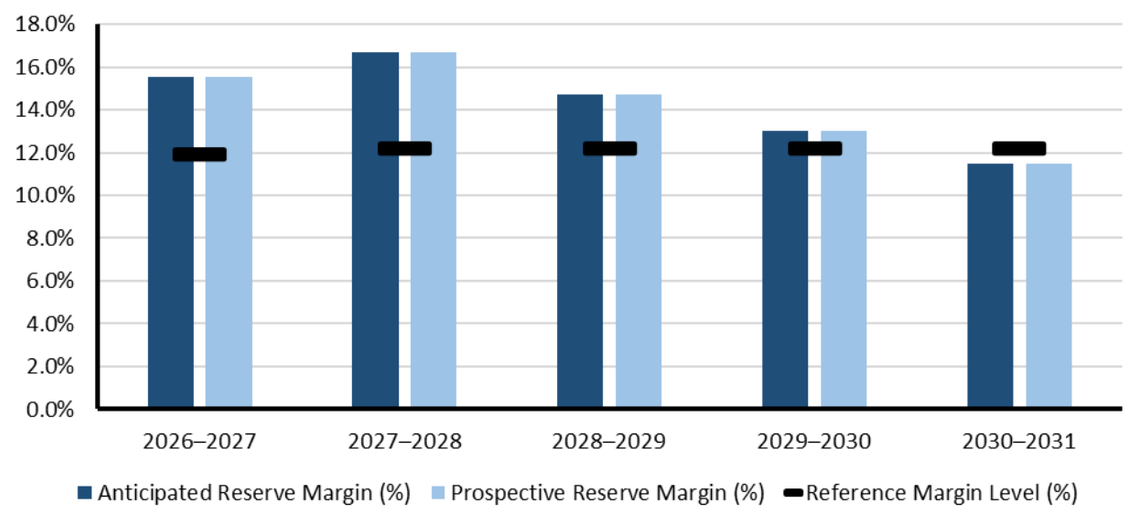


## NPCC-Québec

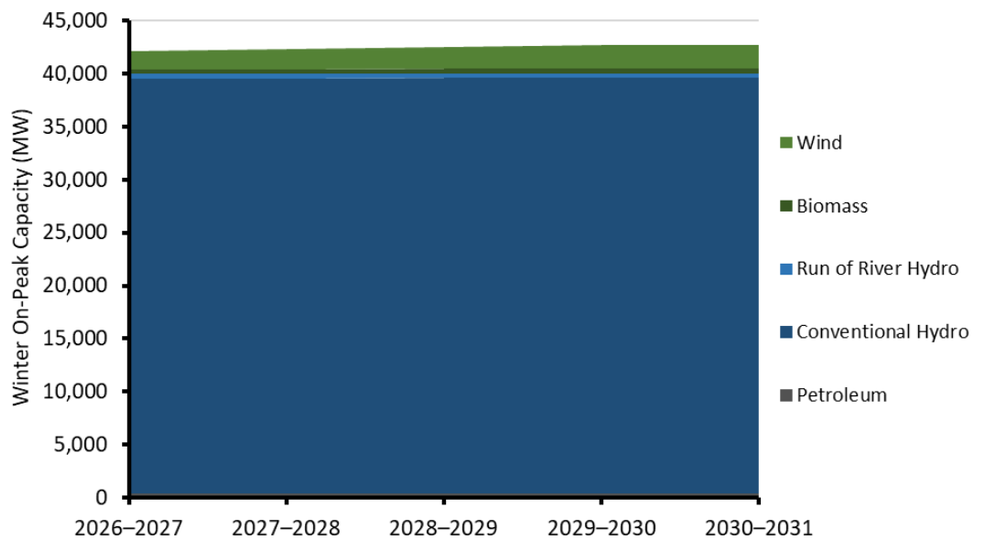
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

### Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 41,405 | 41,901 | 42,833 | 43,635 | 44,392 | 45,116 | 46,053 | 47,148 | 48,164 | 49,613 |
| Demand Response | 5,058 | 5,224 | 5,367 | 5,445 | 5,533 | 5,587 | 5,618 | 5,606 | 5,562 | 5,562 |
| Net Internal Demand | 36,347 | 36,677 | 37,465 | 38,191 | 38,859 | 39,529 | 40,435 | 41,542 | 42,602 | 44,051 |
| Additions: Tier 1 | 412 | 566 | 710 | 891 | 891 | 891 | 891 | 891 | 891 | 891 |
| Additions: Tier 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | -145 | 455 | 455 | 455 | 600 | 0 | 0 | 0 | 0 | 0 |
| Existing-Certain and Net Firm Transfers | 41,591 | 42,231 | 42,269 | 42,272 | 42,421 | 41,825 | 41,830 | 41,834 | 41,838 | 41,842 |
| Anticipated Reserve Margin (%) | 15.6% | 16.7% | 14.7% | 13.0% | 11.5% | 8.1% | 5.7% | 2.9% | 0.3% | -3.0% |
| Prospective Reserve Margin (%) | 15.6% | 16.7% | 14.7% | 13.0% | 11.5% | 8.1% | 5.7% | 2.9% | 0.3% | -3.0% |
| Reference Margin Level (%) | 11.9% | 12.2% | 12.2% | 12.2% | 12.2% | 12.2% | 12.2% | 12.2% | 12.2% | 12.2% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

| NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 |
| Petroleum | 429 | 429 | 429 | 429 | 429 |
| Biomass | 405 | 405 | 405 | 405 | 405 |
| Wind[46] | 1,778 | 1,931 | 2,076 | 2,257 | 2,257 |
| Conventional Hydro | 39,091 | 39,129 | 39,167 | 39,170 | 39,175 |
| Run of River Hydro | 445 | 447 | 447 | 447 | 447 |
| Total MW | 42,148 | 42,342 | 42,524 | 42,708 | 42,712 |

[46] Expected at-peak capacity.

## NPCC-Québec Assessment

**Planning Reserve Margins**
ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec's installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**
Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.[47]

| ProbA Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027-2028** | **2029-2030** |
| EUE (MWh) | 8.205 | 0.01 | 62.99 |
| NEUE (ppm) | 0.040 | 0.000 | 0.29 |
| LOLH (hours per Year) | 0.014 | 0.000 | 0.11 |
| ***Provides the 2024 ProbA Results for Comparison** | | | |

**Demand**
Québec's demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

**Demand-Side Management**
Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

**Distributed Energy Resources**
BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec's winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

**Generation**
4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

**Energy Storage**
No energy storage resources are currently planned for commissioning during the assessment period.

[47] 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

**Capacity Transfers**
Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

**Transmission**
Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

**Reliability Issues**
Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec's large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

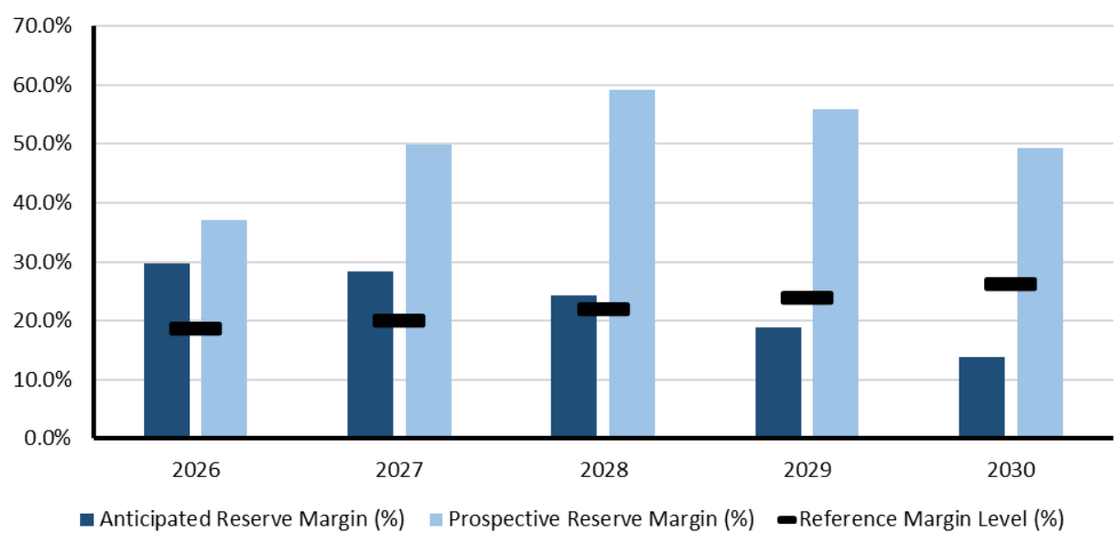


# PJM

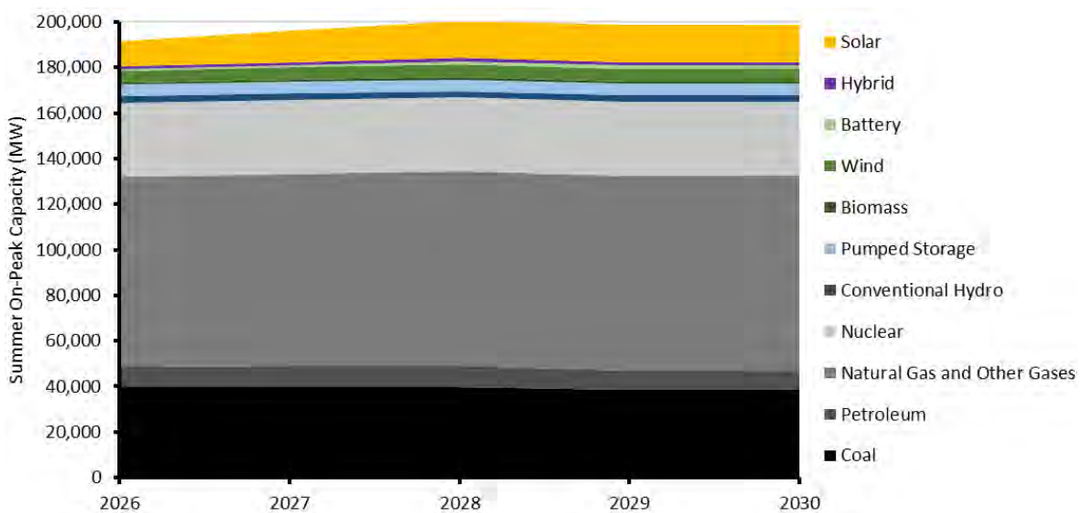
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and has an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 158,937 | 164,186 | 169,981 | 176,094 | 183,883 | 192,647 | 200,507 | 204,197 | 207,253 | 209,923 |
| Demand Response | 8,184 | 8,439 | 8,703 | 9,002 | 9,398 | 9,845 | 10,250 | 10,409 | 10,533 | 10,629 |
| Net Internal Demand | 150,753 | 155,747 | 161,278 | 167,092 | 174,485 | 182,802 | 190,257 | 193,788 | 196,720 | 199,294 |
| Additions: Tier 1 | 5,861 | 10,177 | 14,521 | 14,709 | 14,709 | 14,709 | 14,709 | 14,709 | 14,709 | 14,709 |
| Additions: Tier 2 | 12,410 | 38,519 | 65,315 | 71,119 | 75,116 | 75,290 | 77,655 | 77,655 | 77,655 | 77,655 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | 3,840 | 3,818 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing-Certain and Net Firm Transfers | 189,693 | 189,644 | 186,005 | 184,030 | 184,030 | 184,030 | 184,030 | 184,030 | 184,030 | 184,030 |
| Anticipated Reserve Margin (%) | 29.7% | 28.3% | 24.3% | 18.9% | 13.9% | 8.7% | 4.5% | 2.6% | 1.0% | -0.3% |
| Prospective Reserve Margin (%) | 37.0% | 49.9% | 59.1% | 55.9% | 49.3% | 42.6% | 27.7% | 25.4% | 23.5% | 20.0% |
| Reference Margin Level (%) | 18.6% | 20.1% | 21.9% | 23.9% | 26.3% | 28.9% | 30.8% | 33.0% | 35.1% | 35.1% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

| PJM Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Coal | 39,866 | 39,866 | 39,866 | 38,288 | 38,288 |
| Coal* | 39,866 | 37,738 | 27,448 | 28,002 | 26,464 |
| Petroleum | 8,952 | 9,163 | 9,163 | 8,766 | 8,766 |
| Natural Gas | 83,210 | 84,150 | 85,385 | 85,385 | 85,385 |
| Natural Gas* | 82,589 | 83,443 | 84,678 | 84,678 | 84,678 |
| Biomass | 857 | 907 | 907 | 907 | 907 |
| Solar | 11,282 | 13,616 | 16,141 | 16,328 | 16,328 |
| Wind | 5,251 | 5,496 | 5,622 | 5,622 | 5,622 |
| Conventional Hydro | 2,807 | 2,829 | 2,829 | 2,829 | 2,829 |
| Pumped Storage | 5,068 | 5,068 | 5,068 | 5,068 | 5,068 |
| Nuclear | 32,508 | 32,508 | 32,508 | 32,508 | 32,508 |
| Hybrid | 1,187 | 1,504 | 1,504 | 1,504 | 1,504 |
| Battery | 703 | 895 | 1,531 | 1,531 | 1,531 |
| Total MW | 191,712 | 196,002 | 200,524 | 198,737 | 198,737 |
| Total MW* | 191,091 | 193,166 | 187,399 | 187,743 | 186,205 |
| ***Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked. | | | | | |

## PJM Assessment

**Planning Reserve Margins**
The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.[48]

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**
Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

**Probabilistic Assessments (NERC ProbA and Other Studies)**
LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 538 | 3,251 | 67,580 |
| NEUE (ppm) | 0.00 | 3.50 | 65.50 |
| LOLH (hours per Year) | 0.11 | 0.61 | 9.97 |
| * **Provides the 202**4 ProbA Results for Comparison | | | |

**Demand**
The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

[48] https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM's projected load indicators in many instances have doubled from the *2024 LTRA* projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year's projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

**Demand-Side Management**

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM's probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

**Distributed Energy Resources**

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

**Generation**

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original *2025 LTRA* data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM's Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

**Energy Storage**

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

**Capacity Transfers**

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if its transfers were dropped to zero.

**Transmission**

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved $5.9 billion worth of regional and local projects to address the reliability criteria violations.

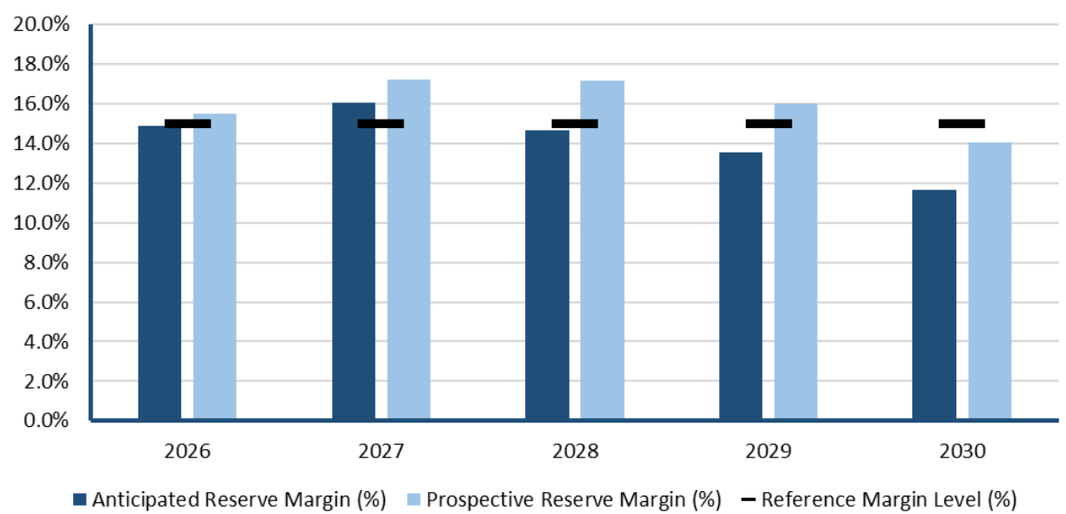


# SERC-Central

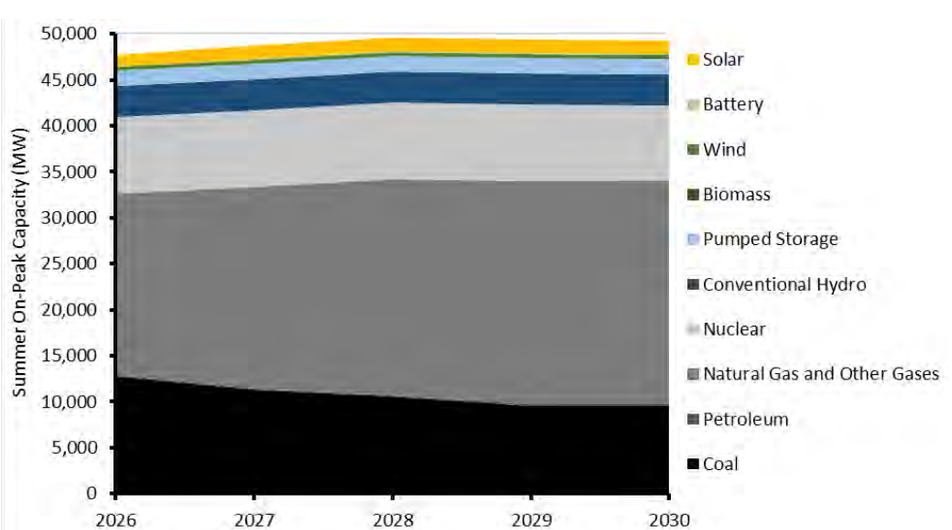
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 43,066 | 43,512 | 44,298 | 44,616 | 45,280 | 45,975 | 46,034 | 46,168 | 46,412 | 46,619 |
| Demand Response | 2,818 | 3,047 | 3,287 | 3,356 | 3,364 | 3,377 | 3,392 | 3,367 | 3,323 | 3,301 |
| Net Internal Demand | 40,248 | 40,465 | 41,011 | 41,260 | 41,916 | 42,598 | 42,642 | 42,801 | 43,089 | 43,317 |
| Additions: Tier 1 | 518 | 492 | 4,567 | 5,435 | 5,435 | 5,435 | 5,435 | 5,435 | 5,435 | 5,735 |
| Additions: Tier 2 | 20 | 245 | 837 | 837 | 837 | 837 | 837 | 837 | 837 | 837 |
| Additions: Tier 3 | 178 | 234 | 300 | 362 | 743 | 795 | 2,107 | 3,293 | 5,539 | 5,591 |
| Net Firm Capacity Transfers | 460 | 391 | -288 | -287 | -287 | -221 | -221 | -220 | -220 | -157 |
| Existing-Certain and Net Firm Transfers | 47,859 | 47,438 | 45,895 | 44,503 | 43,474 | 43,382 | 43,448 | 42,484 | 42,485 | 41,414 |
| Anticipated Reserve Margin (%) | 19.1% | 20.8% | 19.7% | 18.5% | 16.5% | 14.8% | 12.4% | 12.0% | 8.7% | 9.0% |
| Prospective Reserve Margin (%) | 19.7% | 22.0% | 22.3% | 21.1% | 19.0% | 17.3% | 14.9% | 14.5% | 11.2% | 11.5% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

| SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 12,782 | 11,308 | 10,595 | 9,565 | 9,565 |
| Coal* | **12,782** | **11,308** | **9,944** | **8,914** | **8,914** |
| Petroleum | 128 | 128 | 128 | 128 | 128 |
| Natural Gas | 19,706 | 21,956 | 23,483 | 24,341 | 24,249 |
| Natural Gas* | **19,279** | **21,529** | **22,585** | **23,443** | **23,443** |
| Biomass | 37 | 37 | 37 | 37 | 37 |
| Solar | 1,181 | 1,408 | 1,445 | 1,455 | 1,455 |
| Wind | 370 | 370 | 370 | 370 | 370 |
| Conventional Hydro | 3,405 | 3,405 | 3,405 | 3,405 | 3,405 |
| Pumped Storage | 1,247 | 1,247 | 1,247 | 1,247 | 1,247 |
| Nuclear | 8,280 | 8,280 | 8,280 | 8,280 | 8,280 |
| Battery | 100 | 135 | 135 | 135 | 135 |
| Total MW | 47,236 | 48,274 | 49,124 | 48,963 | 48,871 |
| **Total MW*** | **47,256** | **48,267** | **47,996** | **47,835** | **47,835** |
| ***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked. | | | | | |

## SERC-Central Assessment

**Planning Reserve Margins**

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the *2024 LTRA*, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities' ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments**

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

**ProbA Results**

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | 2026* | 2027 | 2029 |
| EUE (MWh) | 0.10 | 0 | 0 |
| NEUE (ppm) | 0.00 | 0.00 | 0.00 |
| LOLH (hours per Year) | 0.00 | 0.00 | 0.00 |
| *Provides the 2024 ProbA Results for Comparison | | | |

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

**Demand**

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

**Demand-Side Management**

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

**Distributed Energy Resources**

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity's Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

**Generation**

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the *2024 LTRA*, with entities projecting no new retirements.

**Changing Resource Mix and Operational Considerations:** Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a "burn-in" period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

**Addressing Net Demand Ramping Needs:** Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

**Capacity Contribution Values for Various Resources:** Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

**IBR Performance and Reliability:** Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

**Generator Retirements**

**Natural Gas Fuel Supply Risk:** Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

**Energy Storage**

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

**Capacity Transfers**

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.
- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
  - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
  - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
  - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

**Transmission**

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
  - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
  - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
  - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
  - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability

- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
  - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
  - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
  - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
  - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
  - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
  - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
  - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

**Reliability Issues**

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

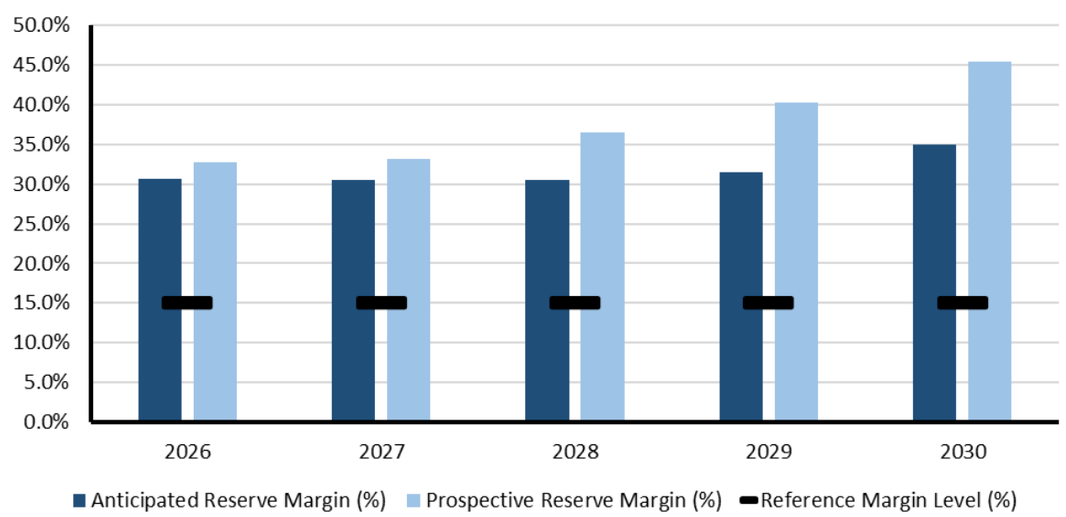


## SERC-East

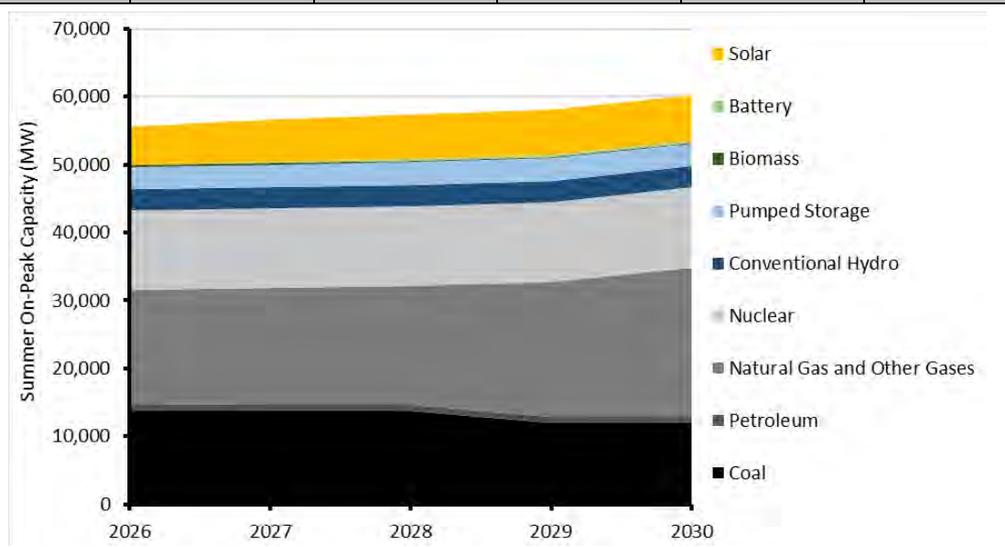
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

### Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 44,414 | 45,289 | 45,893 | 46,128 | 46,646 | 47,256 | 47,776 | 48,445 | 48,870 | 49,313 |
| Demand Response | 1,608 | 1,620 | 1,621 | 1,652 | 1,679 | 1,702 | 1,726 | 1,751 | 1,773 | 1,795 |
| Net Internal Demand | 42,806 | 43,669 | 44,272 | 44,476 | 44,967 | 45,554 | 46,050 | 46,694 | 47,097 | 47,518 |
| Additions: Tier 1 | 959 | 2,109 | 2,817 | 5,282 | 7,348 | 8,656 | 9,921 | 11,186 | 11,186 | 11,186 |
| Additions: Tier 2 | 215 | 484 | 2,009 | 3,231 | 4,045 | 4,551 | 5,114 | 6,232 | 9,022 | 9,022 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | 150 | 150 | 150 | 236 | 236 | 236 | 236 | 236 | 236 | 236 |
| Existing-Certain and Net Firm Transfers | 54,964 | 54,880 | 54,953 | 53,222 | 53,316 | 52,237 | 50,919 | 50,919 | 49,557 | 49,557 |
| Anticipated Reserve Margin (%) | 30.6% | 30.5% | 30.5% | 31.5% | 34.9% | 33.7% | 32.1% | 33.0% | 29.0% | 27.8% |
| Prospective Reserve Margin (%) | 32.7% | 33.1% | 36.5% | 40.3% | 45.4% | 45.1% | 44.7% | 47.8% | 49.5% | 48.2% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

| SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 13,715 | 13,715 | 13,715 | 11,898 | 11,898 |
| Petroleum | 1,044 | 992 | 992 | 992 | 992 |
| Petroleum* | 1,044 | 868 | 868 | 868 | 868 |
| Natural Gas | 16,737 | 17,081 | 17,396 | 19,816 | 21,851 |
| Biomass | 176 | 176 | 176 | 176 | 176 |
| Solar | 5,649 | 6,223 | 6,626 | 6,671 | 6,702 |
| Conventional Hydro | 3,094 | 3,094 | 3,094 | 3,094 | 3,094 |
| Pumped Storage | 3,324 | 3,324 | 3,324 | 3,324 | 3,324 |
| Nuclear | 11,795 | 11,795 | 11,808 | 11,808 | 11,902 |
| Battery | 8 | 208 | 258 | 258 | 258 |
| Total MW | **55,540** | **56,606** | **57,388** | **58,035** | **60,196** |
| **Total MW*** | **55,540** | **56,482** | **57,264** | **57,911** | **60,072** |
| ***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked. | | | | | |

## SERC-East Assessment

**Planning Reserve Margins**

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the *2024 LTRA*, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an "all-of-the-above" strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar, batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through "High" and "Low" load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

**Energy Risk, Probabilistic-Based Assessments**

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC's BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

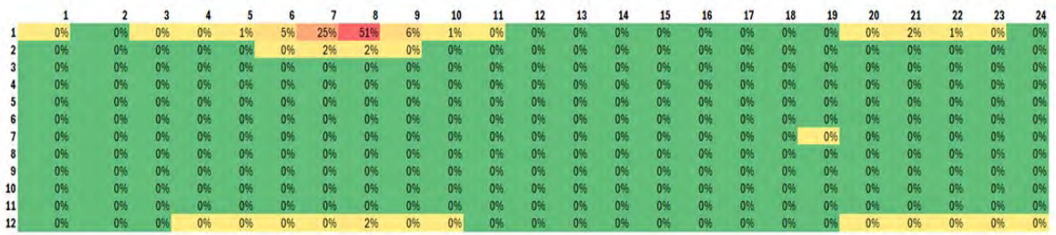
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- ELCC Studies: These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- Statistical Modeling: Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- Stochastic Analysis in Load Forecasting: To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- Load Forecast Uncertainty (LFU) Scenarios: Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

**ProbA Results**

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | 2026* | 2027 | 2029 |
| EUE (MWh) | 143 | 231 | 538 |
| NEUE (ppm) | 0.60 | 0.98 | 2.27 |
| LOLH (hours per Year) | 0.09 | 0.16 | 0.33 |
| *Provides the 2024 ProbA Results for Comparison | | | |

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.




**2027 EUE Heat Map**

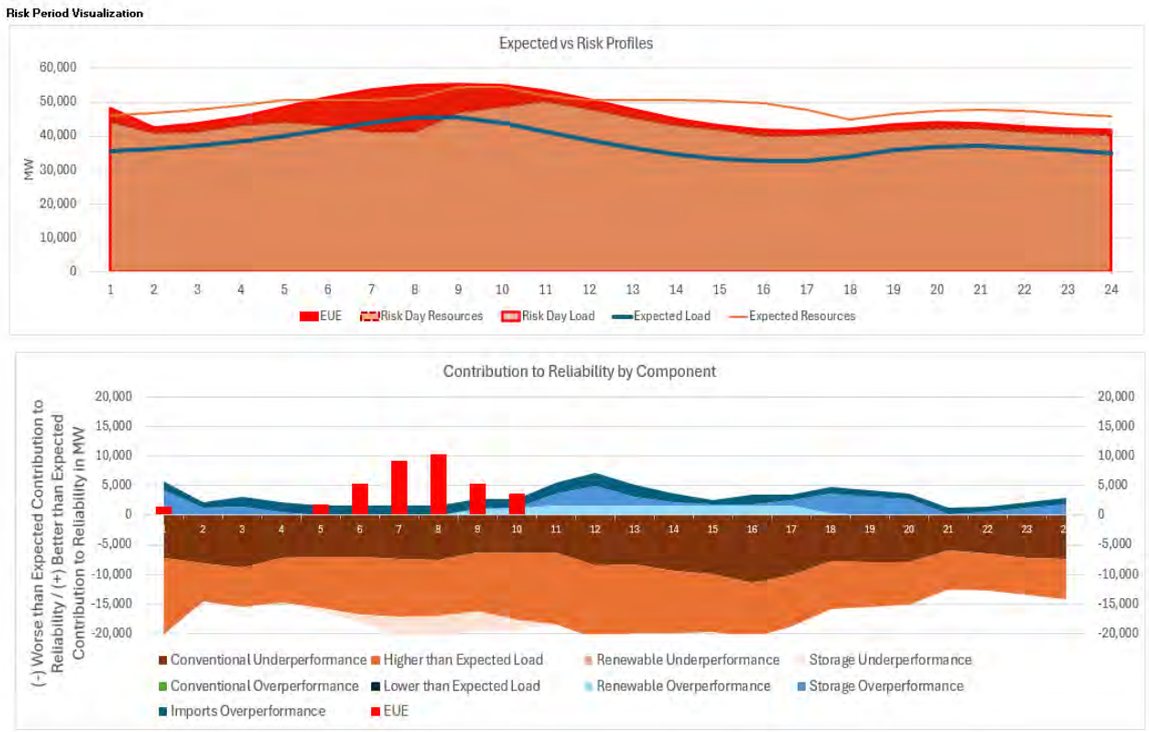
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 1% | 7% | 23% | 41% | 9% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 1% | 3% | 5% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

**2029 EUE Heat Map**

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, the is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProbA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

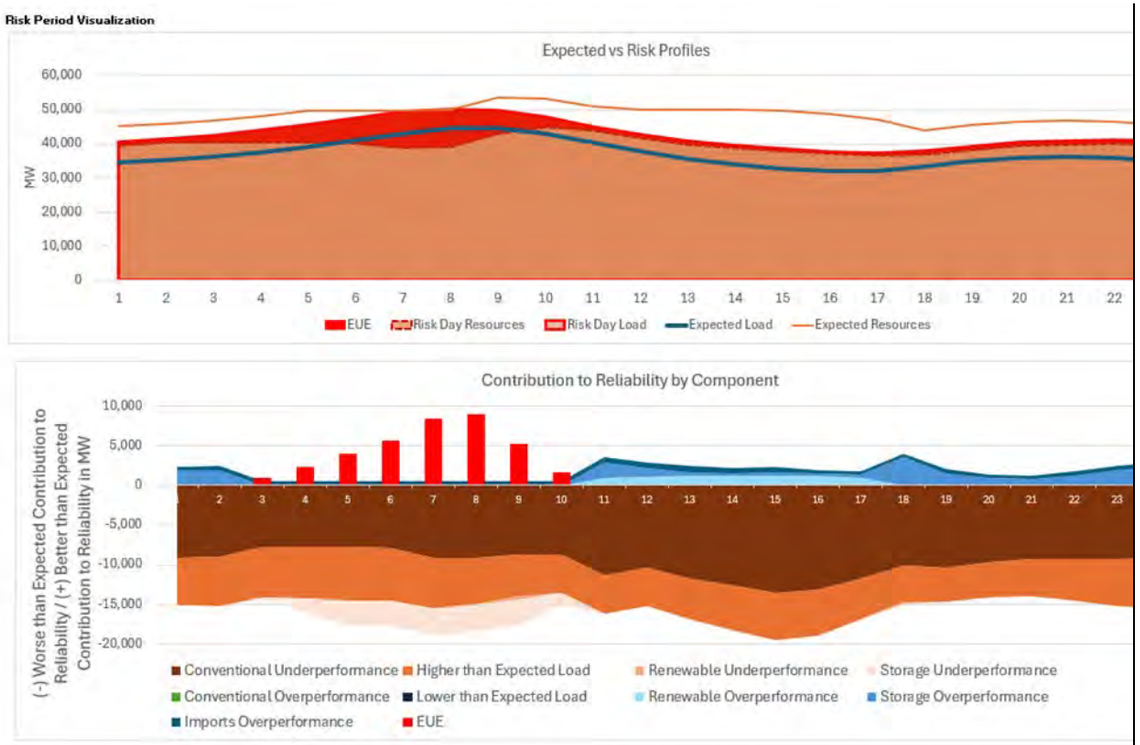
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.




**Expected vs. Risk Profiles and Contribution to Reliability by Component**

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).




Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

**Demand**

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through "High" and "Low" scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the *2024 LTRA* are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

**Demand-Side Management**

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity's capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a "Bring Your Own Thermostat" initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the *2024 LTRA*, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a "Bring Your Own kW" winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the *2024 LTRA*, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

**Distributed Energy Resources**

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the *2024 LTRA*, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

**Generation**

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

**Overall Planning and Resource Mix Evolution**

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

**Capacity Valuation and Reliability**
For resource adequacy, entities determine PRMs to meet reliability standards.

**Capacity Contribution Values:** Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

**Reserve Margins:** Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

**Operational Considerations**
Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

**Energy Storage**
Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

**Purpose:** Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

**Integration:** Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

**Modeling:** BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

**Capacity Transfers**

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

**Transmission**

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the *2024 LTRA*, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

**Reliability Issues**

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

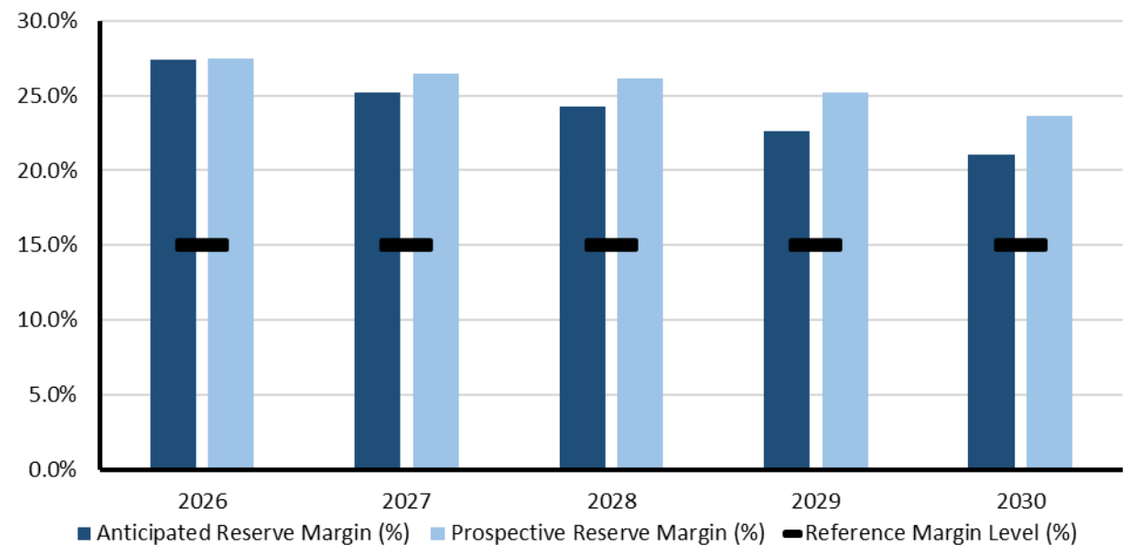


# SERC-Florida Peninsula

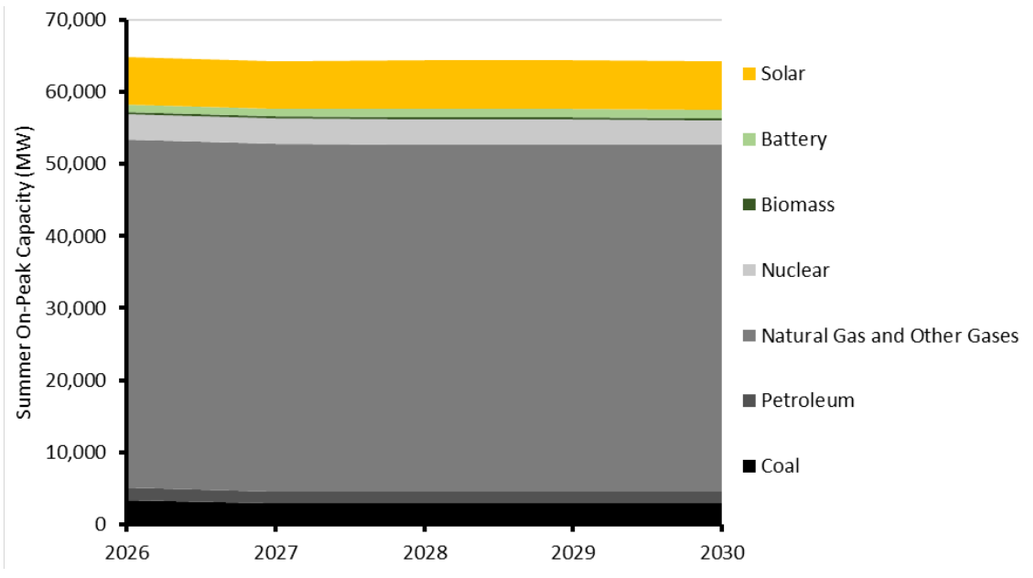
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 54,477 | 54,933 | 55,377 | 56,099 | 56,666 | 57,414 | 58,267 | 58,972 | 59,724 | 60,415 |
| Demand Response | 3,345 | 3,345 | 3,357 | 3,360 | 3,368 | 3,379 | 3,388 | 3,400 | 3,412 | 3,418 |
| Net Internal Demand | 51,132 | 51,588 | 52,020 | 52,739 | 53,298 | 54,035 | 54,879 | 55,572 | 56,312 | 56,997 |
| Additions: Tier 1 | 754 | 800 | 997 | 1,000 | 1,001 | 1,801 | 1,801 | 1,802 | 1,803 | 1,803 |
| Additions: Tier 2 | 32 | 620 | 962 | 1,375 | 1,375 | 1,375 | 1,375 | 1,375 | 1,375 | 1,375 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | 293 | 293 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| Existing-Certain and Net Firm Transfers | 64,393 | 63,795 | 63,659 | 63,659 | 63,525 | 63,001 | 62,966 | 62,966 | 62,966 | 62,966 |
| Anticipated Reserve Margin (%) | 27.4% | 25.2% | 24.3% | 22.6% | 21.1% | 19.9% | 18.0% | 16.5% | 15.0% | 13.6% |
| Prospective Reserve Margin (%) | 27.5% | 26.4% | 26.2% | 25.2% | 23.7% | 22.5% | 20.5% | 19.0% | 17.5% | 16.1% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula's ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

| SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 3,361 | 2,902 | 2,902 | 2,902 | 2,902 |
| Coal* | 3,346 | 2,418 | 2,418 | 2,418 | 2,418 |
| Petroleum | 1,795 | 1,667 | 1,667 | 1,667 | 1,667 |
| Petroleum* | 1,768 | 1,459 | 1,459 | 1,459 | 1,459 |
| Natural Gas | 48,214 | 48,202 | 48,159 | 48,159 | 48,025 |
| Biomass | 310 | 310 | 310 | 310 | 310 |
| Solar | 6,666 | 6,712 | 6,814 | 6,817 | 6,818 |
| Nuclear | 3,502 | 3,502 | 3,502 | 3,502 | 3,502 |
| Battery | 1,000 | 1,000 | 1,095 | 1,095 | 1,095 |
| Total MW | 64,849 | 64,297 | 64,450 | 64,453 | 64,321 |
| Total MW* | **64,806** | **63,604** | **63,757** | **63,760** | **63,628** |
| *Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked. | | | | | |

**Planning Reserve Margins**

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida's Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the *2024 LTRA*, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC's ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé's SERVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

**ProbA Results**

Based on the data and assumptions of SERC's ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | 2026* | 2027 | 2029 |
| EUE (MWh) | 2 | 0 | 0.094 |
| NEUE (ppm) | 0.01 | 0.00 | 0.00 |
| LOLH (hours per Year) | 0.01 | 0.00 | 0.00 |
| * Provides the 2024 ProbA Results for Comparison | | | |

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

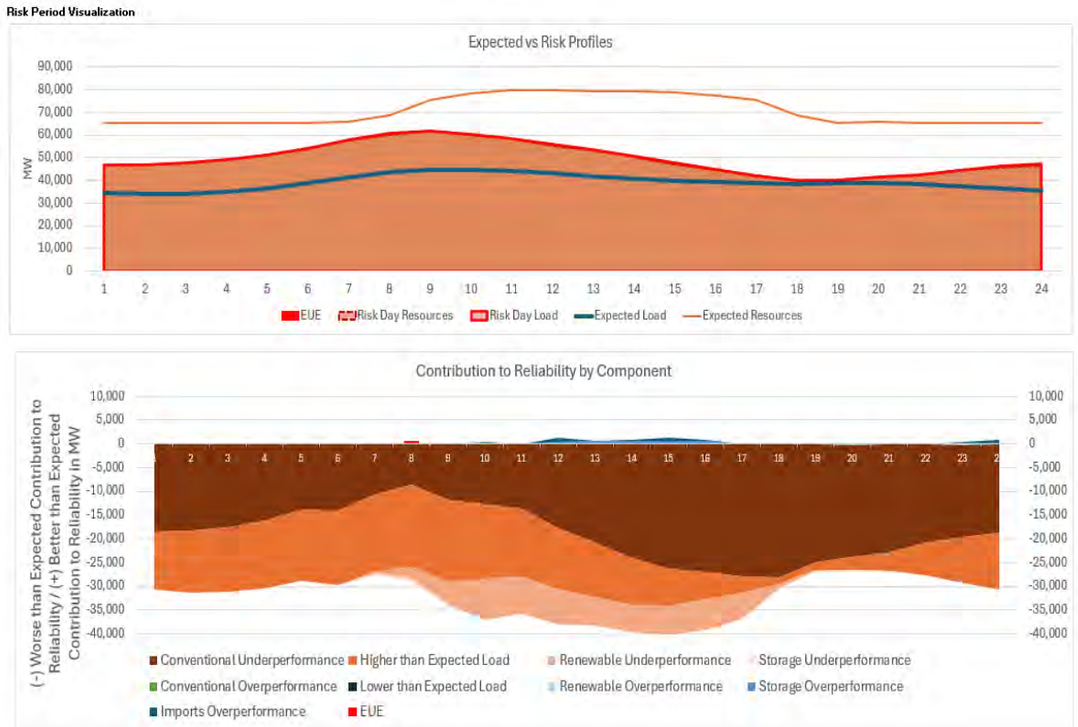
**2027 EUE Heat Map**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 100% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

**2029 EUE Heat Map**

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.




**Expected vs. Risk Profiles and Contribution to Reliability by Component**

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

**Demand**

The Florida Peninsula subregion's approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

**Demand-Side Management**

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

**Distributed Energy Resources**

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

**Penetration and Trends**: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

**Accounting and Integration in Planning**: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

**Monitoring and Studies**: The FRCC's Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

**Challenges and Reliability Impacts**: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

**DER Aggregators**: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members' integrated resource plans via their annual data collection process.

**Generation**

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
  - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
  - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
  - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
  - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
  - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
  - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk
  - The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
  - The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
  - Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
  - Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
  - In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
  - Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

**Net Demand Ramping**

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

**Capacity Contribution Values**

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

**Generator Retirements**

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

**Energy Storage**

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

**Capacity Transfers**

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

**Transmission**

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year's reporting.

**Reliability Issues**

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are "not considered significant in the near-term" for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a "key area of focus."
- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note "no expected hours of shortfall," scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area's "dependency on natural gas as a fuel resource" is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

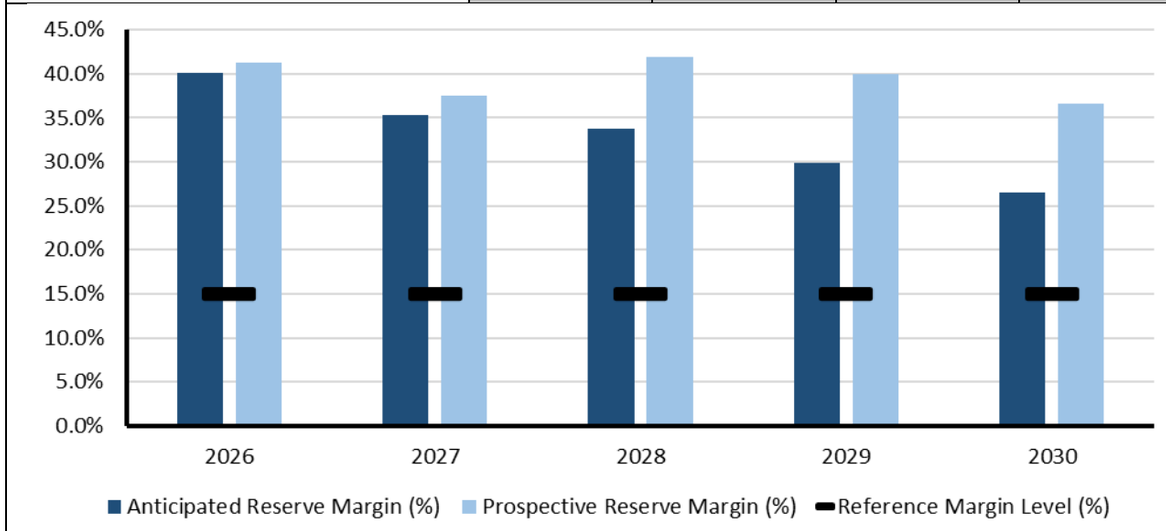


## SERC-Southeast

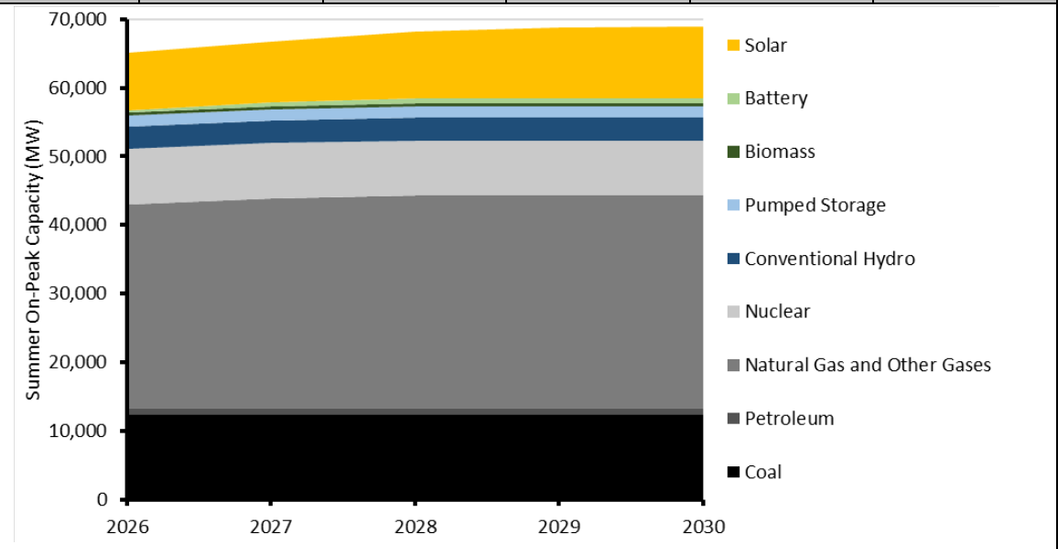
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

### Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 48,386 | 50,648 | 52,900 | 55,127 | 56,624 | 57,544 | 57,978 | 58,552 | 59,004 | 59,166 |
| Demand Response | 1,358 | 1,391 | 1,623 | 1,634 | 1,640 | 1,650 | 1,656 | 1,664 | 1,671 | 1,677 |
| Net Internal Demand | 47,028 | 49,257 | 51,277 | 53,493 | 54,984 | 55,894 | 56,322 | 56,888 | 57,333 | 57,489 |
| Additions: Tier 1 | 684 | 2,262 | 3,704 | 4,395 | 4,474 | 4,474 | 4,474 | 4,474 | 4,474 | 4,474 |
| Additions: Tier 2 | 0 | 516 | 3,687 | 4,889 | 4,989 | 4,989 | 4,989 | 4,989 | 4,989 | 4,989 |
| Additions: Tier 3 | 0 | 150 | 250 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Net Firm Capacity Transfers | 814 | -53 | 414 | 619 | 619 | 619 | 619 | 619 | 619 | 619 |
| Existing-Certain and Net Firm Transfers | 65,201 | 64,393 | 64,860 | 65,065 | 65,065 | 65,065 | 65,065 | 65,065 | 65,065 | 65,065 |
| Anticipated Reserve Margin (%) | 40.1% | 35.3% | 33.7% | 29.8% | 26.5% | 24.4% | 23.5% | 22.2% | 21.3% | 21.0% |
| Prospective Reserve Margin (%) | 41.3% | 37.5% | 42.0% | 40.0% | 36.5% | 34.3% | 33.3% | 32.0% | 30.9% | 30.6% |
| Reference Margin Level (%) | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## SERC-Southeast Highlights

- SERC-Southeast's ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

| SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 12,403 | 12,403 | 12,403 | 12,403 | 12,403 |
| Coal* | 12,403 | 12,403 | 11,145 | 11,145 | 11,145 |
| Petroleum | 866 | 866 | 866 | 866 | 866 |
| Natural Gas | 29,765 | 30,646 | 31,057 | 31,057 | 31,057 |
| Natural Gas* | 29,751 | 30,632 | 31,043 | 31,043 | 31,043 |
| Biomass | 428 | 428 | 428 | 428 | 428 |
| Solar | 8,358 | 8,836 | 9,667 | 10,358 | 10,358 |
| Conventional Hydro | 3,292 | 3,292 | 3,292 | 3,292 | 3,292 |
| Pumped Storage | 1,632 | 1,632 | 1,632 | 1,632 | 1,632 |
| Nuclear | 8,018 | 8,018 | 8,018 | 8,018 | 8,018 |
| Battery | 279 | 557 | 757 | 757 | 836 |
| Total MW | 65,042 | 66,678 | 68,120 | 68,811 | 68,890 |
| Total MW* | 65,042 | 66,678 | 66,862 | 67,553 | 67,632 |
| ***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked. | | | | | |

**Planning Reserve Margins**

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

**ProbA Results**

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | 2026* | 2027 | 2029 |
| EUE (MWh) | 0 | 0.0 | 0.4 |
| NEUE (ppm) | 0.00 | 0.00 | 0.001 |
| LOLH (hours per Year) | 0.00 | 0.00 | 0.001 |
| * Provides the 2024 ProbA Results for Comparison | | | |

The figure below shows the EUE as a Heat Map for the year 2027.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

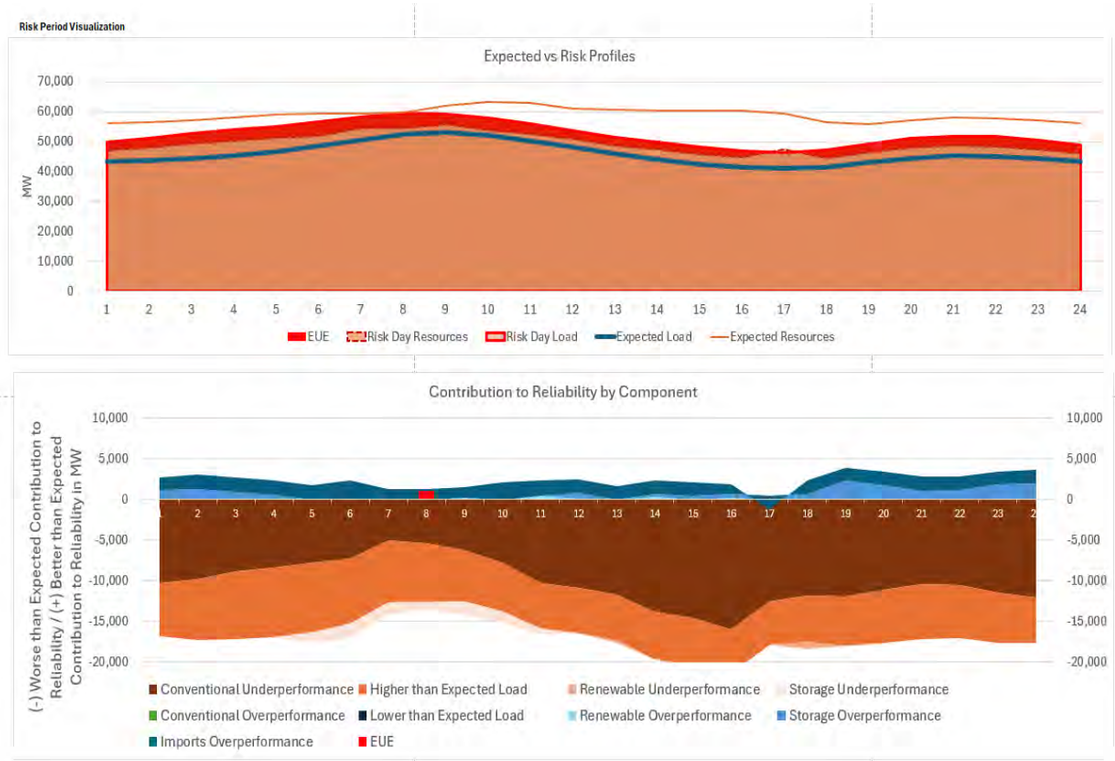
**2027 EUE Heat Map**

For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 13% | 29% |
| 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 35% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 22% | 0% |

**2029 EUE Heat Map**

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.




The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

**Demand**

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

**Demand-Side Management**

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the *2024 LTRA*, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

**Distributed Energy Resources**

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

**Generation**

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area's winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

**Energy Storage**

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

**Capacity Transfers**

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS's ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

**Transmission**

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

**Reliability Issues**

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads**: Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.
- **Natural Gas Fuel Supply Vulnerability**: Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions**: The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

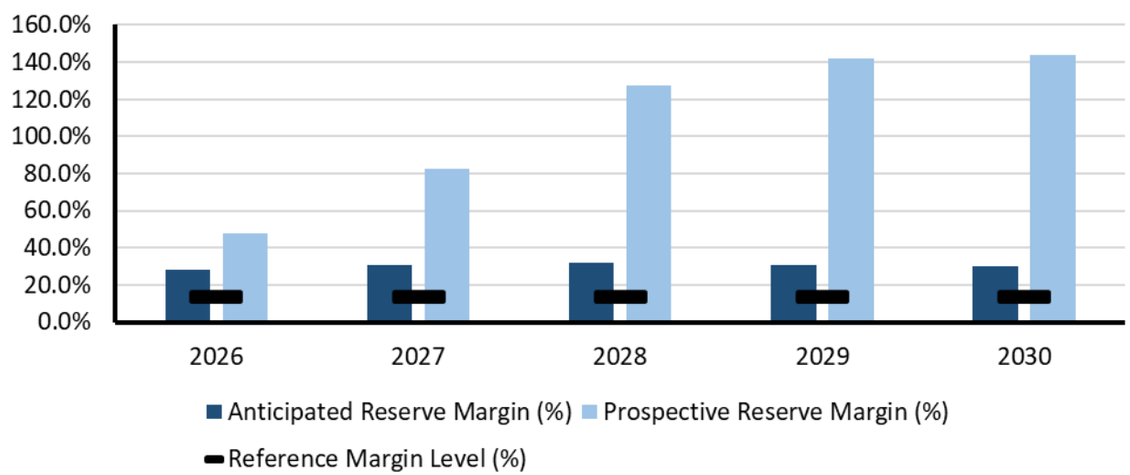


# Texas RE-ERCOT

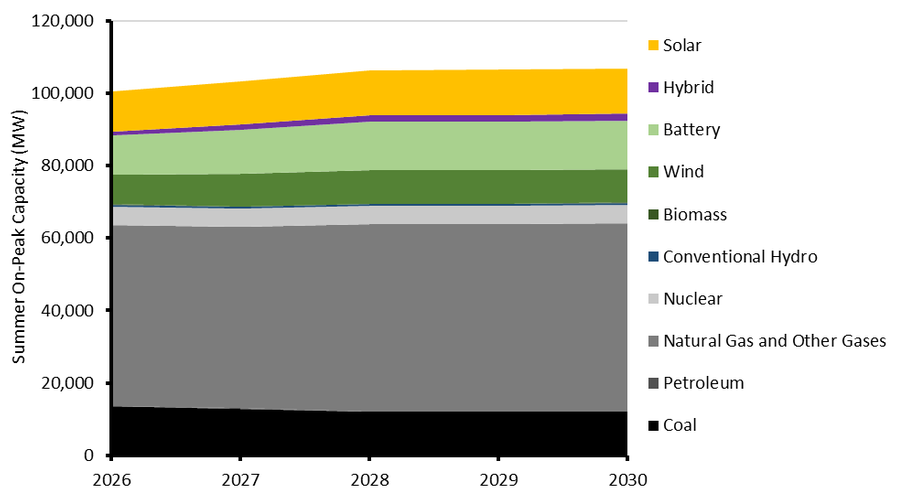
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 94,650 | 104,295 | 121,543 | 128,851 | 138,944 | 144,522 | 148,567 | 149,846 | 152,230 | 154,077 |
| Demand Response | 13,346 | 22,127 | 37,672 | 43,888 | 53,131 | 57,720 | 60,942 | 61,846 | 62,644 | 63,321 |
| Net Internal Demand | 81,304 | 82,168 | 83,871 | 84,963 | 85,813 | 86,802 | 87,625 | 88,000 | 89,586 | 90,756 |
| Additions: Tier 1 | 10,377 | 15,216 | 18,527 | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 | 19,037 |
| Additions: Tier 2 | 15,391 | 42,413 | 79,923 | 95,374 | 98,707 | 99,018 | 99,018 | 99,018 | 99,018 | 99,018 |
| Additions: Tier 3 | 5,022 | 17,546 | 36,405 | 51,080 | 58,217 | 58,217 | 58,463 | 58,463 | 58,463 | 58,463 |
| Net Firm Capacity Transfers | 508 | 659 | 1,122 | 1,122 | 1,122 | 1,122 | 1,122 | 1,122 | 1,122 | 1,122 |
| Existing-Certain and Net Firm Transfers | 93,870 | 92,008 | 92,046 | 92,113 | 92,401 | 92,401 | 92,401 | 92,401 | 92,401 | 92,401 |
| Anticipated Reserve Margin (%) | 28.2% | 30.5% | 31.8% | 30.8% | 29.9% | 28.4% | 27.2% | 26.6% | 24.4% | 22.8% |
| Prospective Reserve Margin (%) | 47.9% | 82.3% | 127.3% | 142.1% | 143.9% | 141.5% | 139.2% | 138.2% | 134.0% | 131.0% |
| Reference Margin Level (%) | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% | 13.75% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
  - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

| Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 13,596 | 12,941 | 12,156 | 12,156 | 12,156 |
| Coal* | 13,596 | 12,550 | 11,205 | 11,205 | 11,205 |
| Petroleum | 30 | 30 | 30 | 30 | 30 |
| Natural Gas | 50,032 | 50,122 | 51,689 | 51,689 | 51,977 |
| Natural Gas* | 50,032 | 49,764 | 51,331 | 51,331 | 51,619 |
| Biomass | 131 | 131 | 131 | 131 | 131 |
| Solar | 11,049 | 11,923 | 12,305 | 12,534 | 12,534 |
| Wind | 8,303 | 8,900 | 9,215 | 9,219 | 9,219 |
| Conventional Hydro | 570 | 570 | 570 | 570 | 570 |
| Nuclear | 4,973 | 4,973 | 4,973 | 4,973 | 4,973 |
| Hybrid | 1,127 | 1,497 | 1,813 | 1,909 | 1,909 |
| Battery | 10,734 | 12,285 | 13,375 | 13,374 | 13,374 |
| Total MW | **100,545** | **103,372** | **106,257** | **106,584** | **106,872** |
| Total MW* | **100,545** | 102,203 | 104,528 | 104,855 | 105,143 |

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.
**Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.

**Planning Reserve Margins**

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year's LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

**Energy Risk, Including Non-Peak Hour Risk**

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

**Probabilistic Assessments (NERC ProbA and Other Studies)**

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 11,090 | 5,864 | 17,053 |
| NEUE (ppm) | 18.95 | 8.70 | 18.84 |
| LOLH (hours per Year) | 1.57 | 0.94 | 3.64 |
| *** Provides the 2024 ProbA Results for Comparison** | | | |

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 4% | 3% | 2% | 2% | 3% | 5% | 8% | 11% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 4% | 7% | 5% | 4% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 2% | 2% | 2% | 2% | 2% | 3% | 4% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 3% | 4% | 4% |

2029

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 2 | 3% | 2% | 2% | 2% | 3% | 4% | 6% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 3% | 4% | 4% | 4% | 3% |
| 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 0% | 0% | 0% |
| 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 4% | 1% | 0% | 0% |
| 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 6% | 5% | 1% | 0% | 0% |
| 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 0% | 0% | 0% | 0% |
| 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| 12 | 1% | 1% | 1% | 1% | 1% | 2% | 2% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 3% | 2% | 2% | 2% | 2% |

**Demand**

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

| Load Additions in the Load Forecast (MW) (Cumulative) | | | |
|---|---|---|---|
| **Load Type** | **End of Year 2 (2027)** | **End of Year 5 (2030)** | **End of Year 10 (2035)** |
| Data Centers | **6,700** | **23,000** | **25,000** |
| Cryptocurrency Mining Facilities | **4,500** | **7,500** | **8,500** |
| Hydrogen Electrolysis | **3,000** | **7,902** | **9,100** |
| Industrial Manufacturing Load | **2,800** | **7,100** | **7,600** |

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT's load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

**Demand-Side Management**

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the "Controllable and Dispatchable Demand Response" line items.

| Summer | Total LL (MW) | LL Curtailment (MW) | | Winter | Total LL (MW) | LL Curtailment (MW) |
|---|---|---|---|---|---|---|
| 2025 (S) | 3864.4 | 1,313.9 | | 2025-26 (W) | 9112.9 | 8,227.7 |
| 2026 (S) | 12355.4 | 8,853.5 | | 2026-27 (W) | 17289.8 | 15,909.3 |
| 2027 (S) | 21665.7 | 17,171.5 | | 2027-28 (W) | 31590.8 | 29,408.9 |
| 2028 (S) | 38583.3 | 32,716.5 | | 2028-29 (W) | 45249.3 | 42,298.1 |
| 2029 (S) | 45681.1 | 38,932.6 | | 2029-30 (W) | 55533.1 | 51,981.4 |
| 2030 (S) | 55964.9 | 48,175.5 | | 2030-31 (W) | 60917.9 | 57,010.6 |
| 2031 (S) | 61349.7 | 52,764.3 | | 2031-32 (W) | 64863.6 | 60,672.7 |
| 2032 (S) | 65295.4 | 55,985.9 | | 2032-33 (W) | 66370.5 | 62,017.8 |
| 2033 (S) | 66802.3 | 56,890.6 | | 2033-34 (W) | 67764.7 | 63,256.0 |
| 2034 (S) | 68196.5 | 57,688.4 | | 2034-35 (W) | 69032.1 | 64,373.6 |
| 2035 (S) | 69463.9 | 58,365.6 | | 2035-36 (W) | 69805.1 | 65,043.3 |

**Distributed Energy Resources**

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called "Unregistered Distributed Generators" (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

**Generation**

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year "Reliability Must Run" (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

**Energy Storage**

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single "integrated" generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT's "Real Time Co-Optimization + Battery" project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

**Capacity Transfers (Reliance on Assistance)**

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

**Transmission**

ERCOT's 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP's 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

**Reliability Issues**

There are several reliability concerns associated with the rapid growth in large loads:

**Loss of Load:** Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

**Load Forecasting Challenges:** The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT's Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

**Potential Subsynchronous Oscillation Vulnerabilities:** Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

**Need for a Large Load Interconnection Study Process:** ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

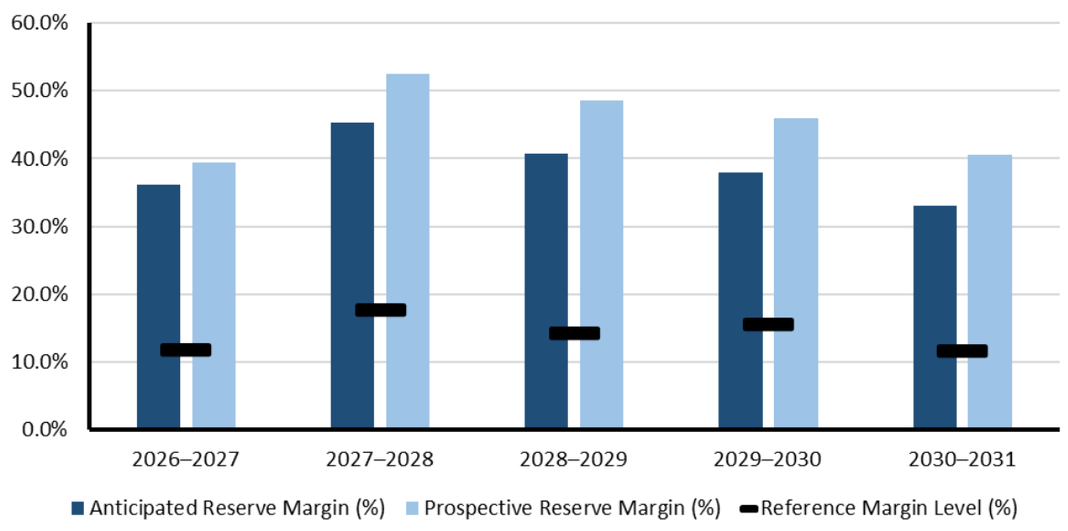


# WECC-Alberta

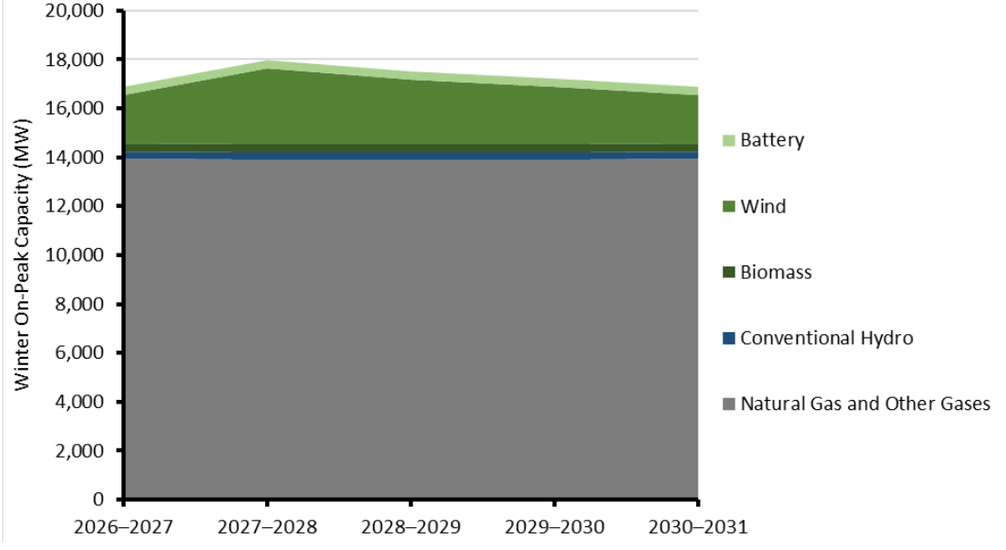
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 12,463 | 12,434 | 12,510 | 12,528 | 12,759 | 12,831 | 12,956 | 12,992 | 13,076 | 13,470 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Internal Demand | 12,463 | 12,434 | 12,510 | 12,528 | 12,759 | 12,831 | 12,956 | 12,992 | 13,076 | 13,470 |
| Additions: Tier 1 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 |
| Additions: Tier 2 | 393 | 889 | 983 | 1,009 | 959 | 1,009 | 921 | 971 | 971 | 971 |
| Additions: Tier 3 | 392 | 658 | 917 | 1,297 | 1,334 | 1,631 | 1,635 | 1,751 | 1,751 | 1,751 |
| Net Capacity Transfers (WECC Model) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing-Certain and Net Transfers | 16,764 | 17,856 | 17,394 | 17,074 | 16,764 | 17,074 | 16,502 | 16,820 | 16,820 | 16,820 |
| Anticipated Reserve Margin (%) | 36.2% | 45.3% | 40.7% | 38.0% | 33.0% | 34.7% | 29.0% | 31.1% | 30.2% | 26.4% |
| Prospective Reserve Margin (%) | 39.3% | 52.4% | 48.6% | 46.0% | 40.5% | 42.6% | 36.1% | 38.5% | 37.7% | 33.6% |
| Reference Margin Level (%) | 11.8% | 17.6% | 14.3% | 15.6% | 11.6% | 15.2% | 12.2% | 14.3% | 13.9% | 13.5% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Alberta Highlights

- WECC-Alberta's ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta's total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta's thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta's 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

| WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 |
| Natural Gas | 13,932 | 13,908 | 13,890 | 13,900 | 13,932 |
| Biomass | 336 | 336 | 335 | 336 | 336 |
| Wind | 2,000 | 3,109 | 2,665 | 2,327 | 2,000 |
| Conventional Hydro | 293 | 301 | 301 | 310 | 293 |
| Other | 81 | 81 | 81 | 81 | 81 |
| Battery | 330 | 330 | 329 | 330 | 330 |
| Total MW | 16,973 | 18,065 | 17,602 | 17,283 | 16,973 |

## WECC-Alberta Assessment

**Planning Reserve Margins**
WECC-Alberta's ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

**Energy Risk, Including Non-Peak Hour Risk**
AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

**ProbA Results**

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 0 | 0 | 0 |
| NEUE (ppm) | 0.00 | 0.00 | 0.00 |
| LOLH (hours per Year) | 0.00 | 0.00 | 0.00 |
| *** Provides the 2024 ProbA Results for Comparison** | | | |

**Demand**
Alberta's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

**Demand-Side Management**
AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

**Generation**
Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO's ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC's load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO's system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is 30% renewable by 2030. Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

**Energy Storage**

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

**Energy Transfers**

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

**Transmission**

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

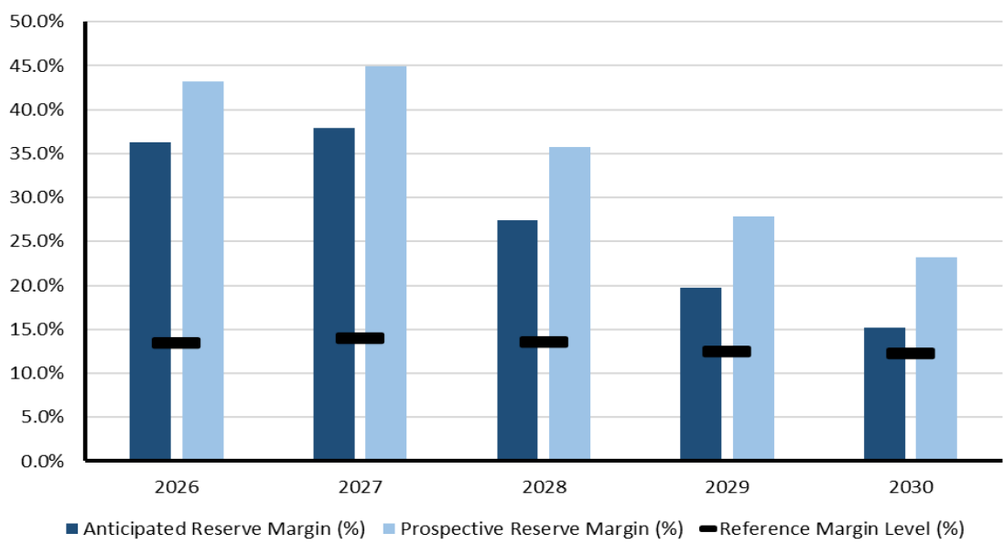


# WECC-Basin

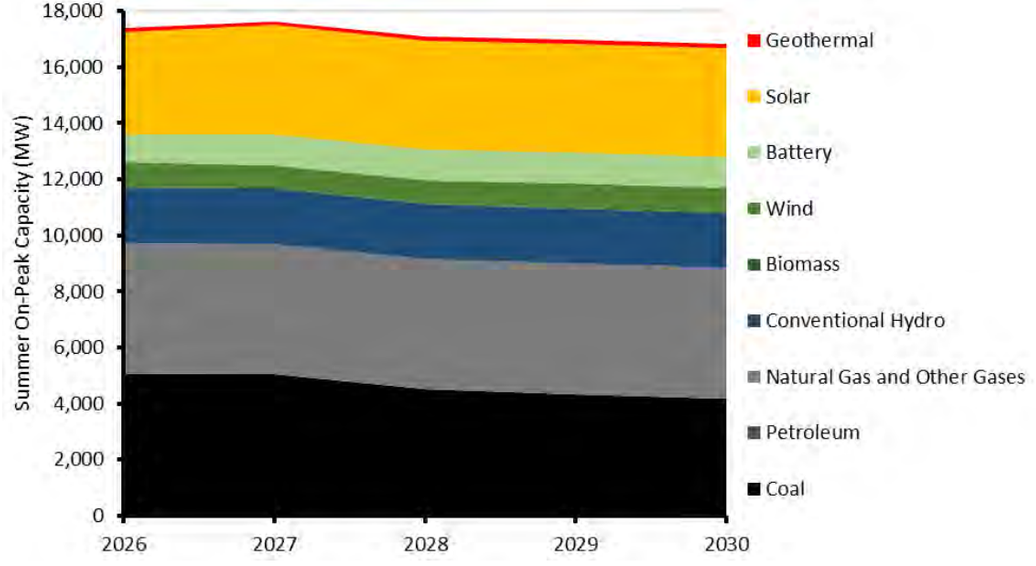
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 14,794 | 15,326 | 16,012 | 16,396 | 16,762 | 17,099 | 17,202 | 17,268 | 17,344 | 17,467 |
| Demand Response | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 670 | 670 |
| Net Internal Demand | 14,124 | 14,656 | 15,342 | 15,726 | 16,092 | 16,429 | 16,532 | 16,598 | 16,674 | 16,797 |
| Additions: Tier 1 | 2,125 | 2,453 | 2,453 | 2,466 | 2,466 | 2,466 | 2,466 | 2,453 | 2,466 | 2,466 |
| Additions: Tier 2 | 973 | 1,018 | 1,270 | 1,279 | 1,279 | 1,279 | 1,279 | 1,270 | 1,279 | 1,279 |
| Additions: Tier 3 | 127 | 1,162 | 2,024 | 2,616 | 4,209 | 4,726 | 5,665 | 6,203 | 6,332 | 6,332 |
| Net Capacity Transfers (WECC Model) | 1,822 | 2,545 | 2,420 | 1,820 | 1,698 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 |
| Existing-Certain and Net Transfers | 17,125 | 17,763 | 17,097 | 16,357 | 16,071 | 15,736 | 15,729 | 15,315 | 15,288 | 15,280 |
| Anticipated Reserve Margin (%) | 36.3% | 37.9% | 27.4% | 19.7% | 15.2% | 10.8% | 10.1% | 7.1% | 6.5% | 5.7% |
| Prospective Reserve Margin (%) | 43.2% | 44.9% | 35.7% | 27.8% | 23.1% | 18.6% | 17.8% | 14.7% | 14.2% | 13.3% |
| Reference Margin Level (%) | 13.5% | 14.0% | 13.6% | 12.4% | 12.3% | 12.1% | 12.1% | 12.5% | 11.8% | 11.8% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

| WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 5,068 | 5,041 | 4,508 | 4,326 | 4,177 |
| Petroleum | 5 | 5 | 5 | 5 | 5 |
| Natural Gas | 4,655 | 4,634 | 4,634 | 4,655 | 4,655 |
| Biomass | 31 | 31 | 31 | 31 | 31 |
| Solar | 3,668 | 3,899 | 3,899 | 3,884 | 3,884 |
| Wind | 900 | 826 | 826 | 897 | 882 |
| Geothermal | 139 | 139 | 139 | 139 | 139 |
| Conventional Hydro | 1,962 | 1,976 | 1,968 | 1,954 | 1,954 |
| Other | 31 | 31 | 31 | 19 | 19 |
| Battery | 967 | 1,090 | 1,090 | 1,092 | 1,092 |
| **Total MW** | **17,428** | **17,672** | **17,130** | **17,003** | **16,839** |

## WECC-Basin Assessment

### Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

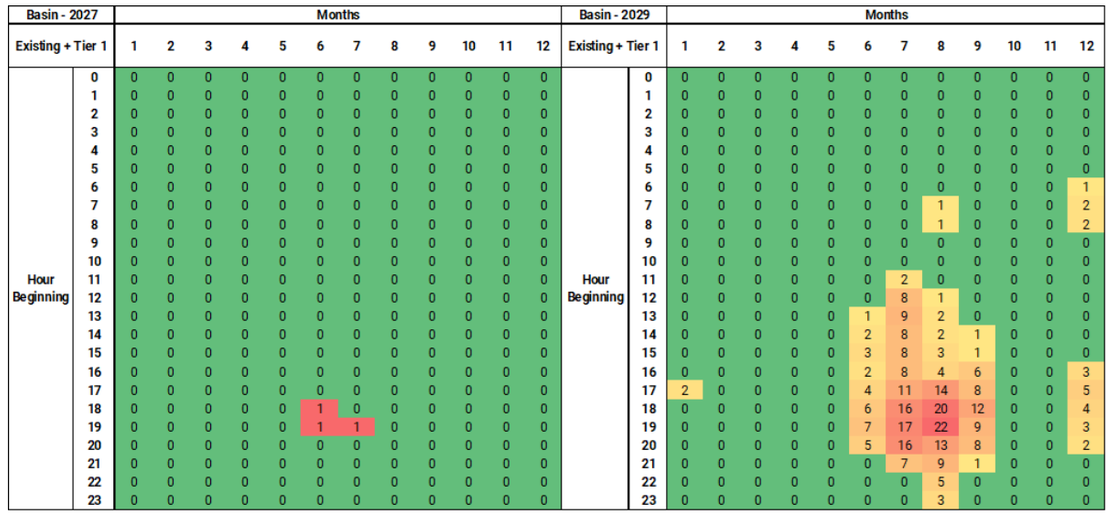
### Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy based ProbAs that support NERC's LTRA and seasonal assessments, as well as WECC's Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area's ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

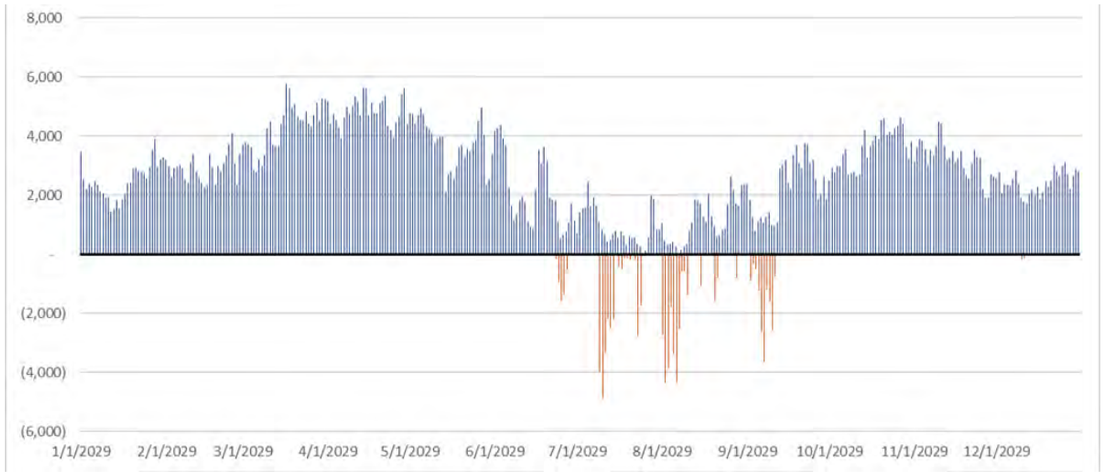
| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | N/A | 3 | 200,892 |
| NEUE (ppm) | N/A | 0.04 | 2250.70 |
| LOLH (hours per Year) | N/A | 3.00 | 310.00 |
| *** No prior results as the assessment area is new for the 2025 LTRA.** | | | |

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.



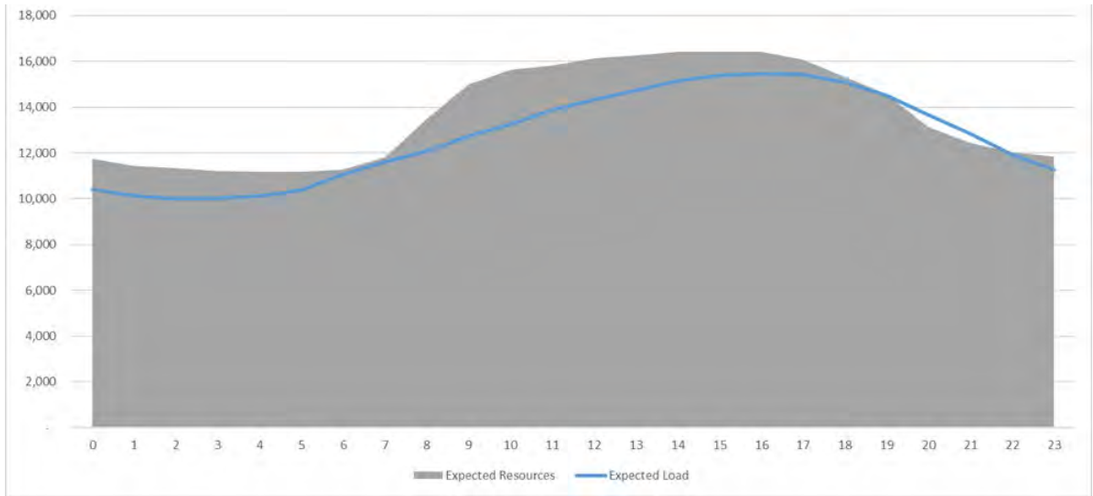

**Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029**

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin's resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.




**Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year**

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.




**Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year**

**Demand**

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company's dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

**Distributed Energy Resources**

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

**Generation**

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

**Electric-Gas Coordination**

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

**Renewable Portfolio, Clean Electricity, and Emissions Standards**

Idaho Power serves ~63% of the state's electricity load and is targeting 100% clean electricity by 2045; Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

**Transmission**

PacifiCorp's Energy Gateway Transmission Plan addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

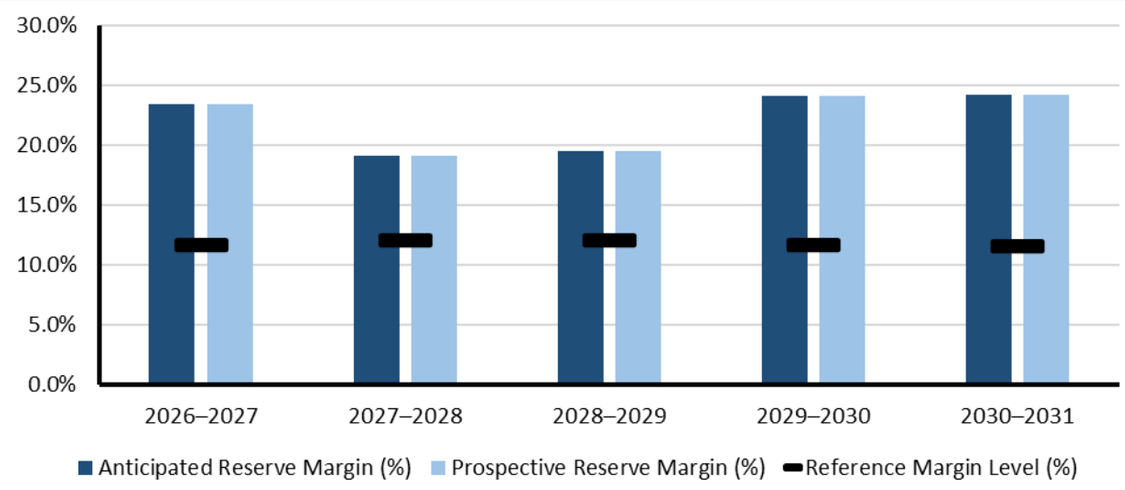


# WECC-British Columbia

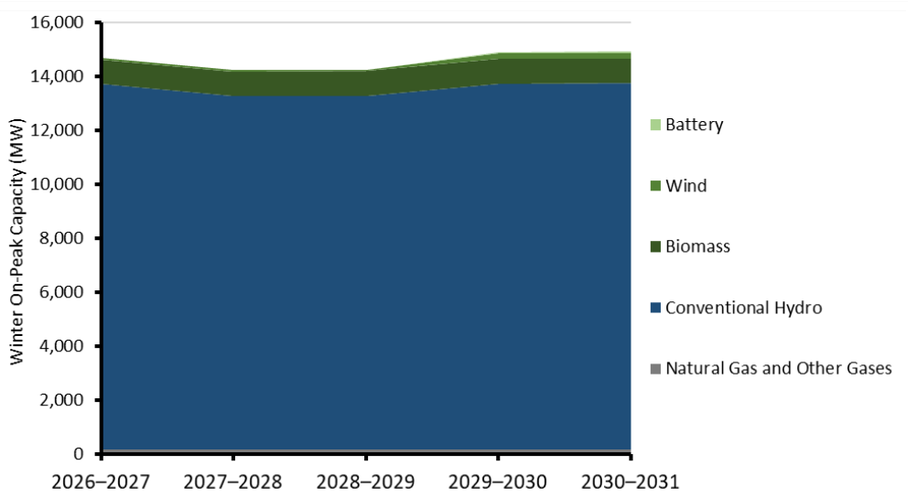
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 11,915 | 11,970 | 11,932 | 12,022 | 12,028 | 12,074 | 12,116 | 12,177 | 12,243 | 12,320 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Internal Demand | 11,915 | 11,970 | 11,932 | 12,022 | 12,028 | 12,074 | 12,116 | 12,177 | 12,243 | 12,320 |
| Additions: Tier 1 | 636 | 620 | 625 | 850 | 863 | 863 | 863 | 814 | 863 | 863 |
| Additions: Tier 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 381 | 369 | 381 | 381 |
| Net Capacity Transfers (WECC Model) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing-Certain and Net Transfers | 14,072 | 13,638 | 13,638 | 14,072 | 14,072 | 14,072 | 14,072 | 13,638 | 14,072 | 14,072 |
| Anticipated Reserve Margin (%) | 23.4% | 19.1% | 19.5% | 24.1% | 24.2% | 23.7% | 23.3% | 18.7% | 22.0% | 21.2% |
| Prospective Reserve Margin (%) | 23.4% | 19.1% | 19.5% | 24.1% | 24.2% | 23.7% | 23.3% | 18.7% | 22.0% | 21.2% |
| Reference Margin Level (%) | 11.7% | 12.1% | 12.1% | 11.6% | 11.6% | 11.6% | 11.5% | 11.9% | 11.5% | 11.4% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-British Columbia Highlights

- WECC-British Columbia's anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro's most recent 10-year capital plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

| WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 |
| Natural Gas | 170 | 170 | 170 | 170 | 170 |
| Biomass | 900 | 903 | 903 | 900 | 900 |
| Wind | 73 | 59 | 59 | 222 | 222 |
| Conventional Hydro | 13,544 | 13,104 | 13,109 | 13,560 | 13,573 |
| Other | 22 | 22 | 22 | 22 | 22 |
| Battery | 0 | 0 | 0 | 49 | 49 |
| Total MW | 14,708 | 14,258 | 14,263 | 14,922 | 14,935 |

## WECC-British Columbia Assessment

**Planning Reserve Margins**

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia's ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For 2025–2026 Winter, monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For 2026 Summer, a PRM range between 14.2% and 22.3% is reported.

**Energy Assessment, including non-peak hour risk**

**ProbA Results**

British Columbia does not show any LOLH or EUE in 2027 or 2029.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | 0 | 0 | 0 |
| NEUE (ppm) | 0.00 | 0.00 | 0.00 |
| LOLH (hours per Year) | 0.00 | 0.00 | 0.00 |
| * Provides the 2024 ProbA Results for Comparison | | | |

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

**Demand**

British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

**Distributed Energy Resources**

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

**Generation**

With its abundant hydro, British Columbia is already approximately 95% carbon free. The CleanBC Roadmap states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean."

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia's capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province's basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year's snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

**Energy Storage**

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

**Energy Transfers**

According to NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

**Transmission**

BC Hydro's most recent 10-Year Capital Plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

**Reliability Issues**

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

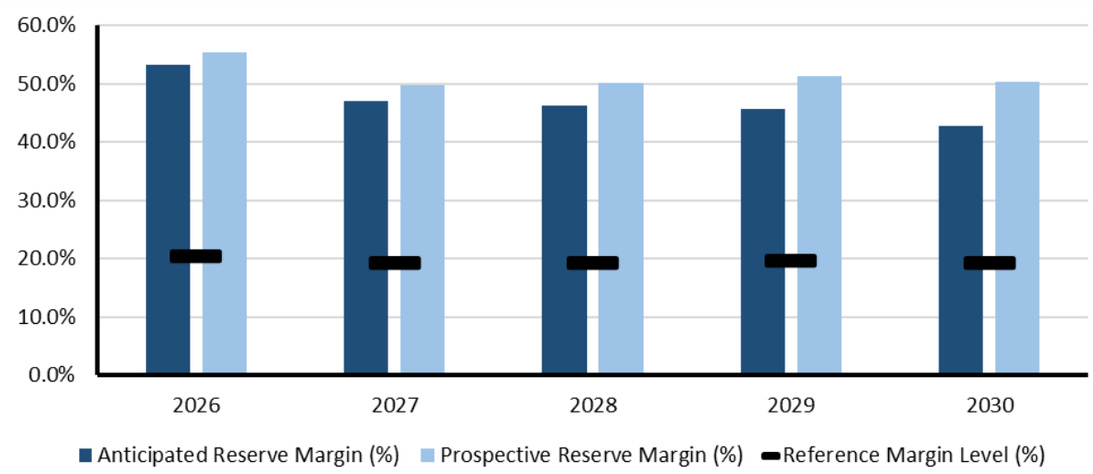


# WECC-California

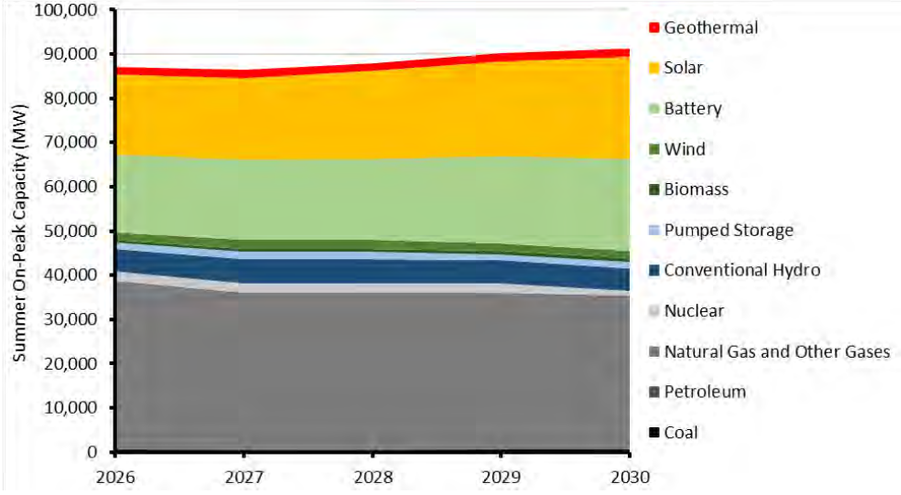
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 58,165 | 60,060 | 61,547 | 63,261 | 65,221 | 66,879 | 68,315 | 69,759 | 71,373 | 73,017 |
| Demand Response | 756 | 764 | 775 | 783 | 795 | 799 | 812 | 823 | 836 | 836 |
| Net Internal Demand | 57,409 | 59,296 | 60,772 | 62,478 | 64,426 | 66,079 | 67,504 | 68,936 | 70,537 | 72,182 |
| Additions: Tier 1 | 11,558 | 13,202 | 14,765 | 17,206 | 19,945 | 19,945 | 21,532 | 22,541 | 23,771 | 25,622 |
| Additions: Tier 2 | 1,288 | 1,552 | 2,388 | 3,489 | 4,974 | 4,974 | 6,509 | 8,475 | 9,208 | 9,244 |
| Additions: Tier 3 | 10 | 10 | 10 | 10 | 557 | 557 | 557 | 562 | 557 | 557 |
| Net Capacity Transfers (WECC Model) | 561 | 583 | 651 | 639 | 541 | 234 | 310 | 314 | 298 | 287 |
| Existing-Certain and Net Transfers | 76,371 | 73,982 | 74,050 | 73,773 | 71,969 | 70,585 | 70,661 | 70,925 | 70,649 | 70,613 |
| Anticipated Reserve Margin (%) | 53.2% | 47.0% | 46.1% | 45.6% | 42.7% | 37.0% | 36.6% | 35.6% | 33.9% | 33.3% |
| Prospective Reserve Margin (%) | 55.4% | 49.6% | 50.1% | 51.2% | 50.4% | 44.5% | 46.2% | 47.9% | 46.9% | 46.1% |
| Reference Margin Level (%) | 20.3% | 19.2% | 19.3% | 19.7% | 19.3% | 19.1% | 18.9% | 17.8% | 18.3% | 18.0% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. CPUC's ruling also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

| WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 466 | 466 | 466 | 466 | 466 |
| Coal* | 16 | 16 | 16 | 16 | 16 |
| Petroleum | 103 | 103 | 103 | 103 | 103 |
| Natural Gas | 38,144 | 35,507 | 35,507 | 35,468 | 34,837 |
| Natural Gas* | 38,144 | 34,994 | 34,994 | 35,468 | 34,837 |
| Biomass | 734 | 745 | 749 | 749 | 749 |
| Solar | 18,126 | 18,574 | 19,936 | 21,506 | 23,065 |
| Wind | 1,643 | 1,991 | 2,000 | 1,650 | 1,650 |
| Geothermal | 1,809 | 1,808 | 1,808 | 1,809 | 1,809 |
| Conventional Hydro | 5,112 | 5,426 | 5,426 | 5,112 | 5,112 |
| Pumped Storage | 1,401 | 1,549 | 1,549 | 1,401 | 1,401 |
| Nuclear | 2,152 | 2,151 | 2,151 | 2,152 | 1,076 |
| Other | 194 | 194 | 194 | 194 | 194 |
| Battery | 17,486 | 18,088 | 18,275 | 19,731 | 20,911 |
| Total MW | 87,368 | 86,601 | 88,164 | 90,340 | 91,372 |
| Total MW* | 86,918 | 85,637 | 87,200 | 89,890 | 90,922 |

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

## WECC-California Assessment

**Planning Reserve Margins**
The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC's reserve margins are not used in WECC's methodology for the LTRA.

**Energy Assessment, including non-peak hour risk**
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

**ProbA Results**
The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | N/A | 0 | 0 |
| NEUE (ppm) | N/A | 0.00 | 0.00 |
| LOLH (hours per Year) | N/A | 0.00 | 0.00 |
| * No prior results as the assessment area is new for the 2025 LTRA. | | | |

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

**Demand**
Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

**Demand-Side Management**
DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

**Distributed Energy Resources**
A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the "net billing tariff" that pays approximately 75% lower rates for energy sent back to the grid. Given California's shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

**Generation**

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

**Electric-Gas Coordination**

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

**Renewable Portfolio, Clean Electricity, and Emissions Standards**

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

**Transmission**

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

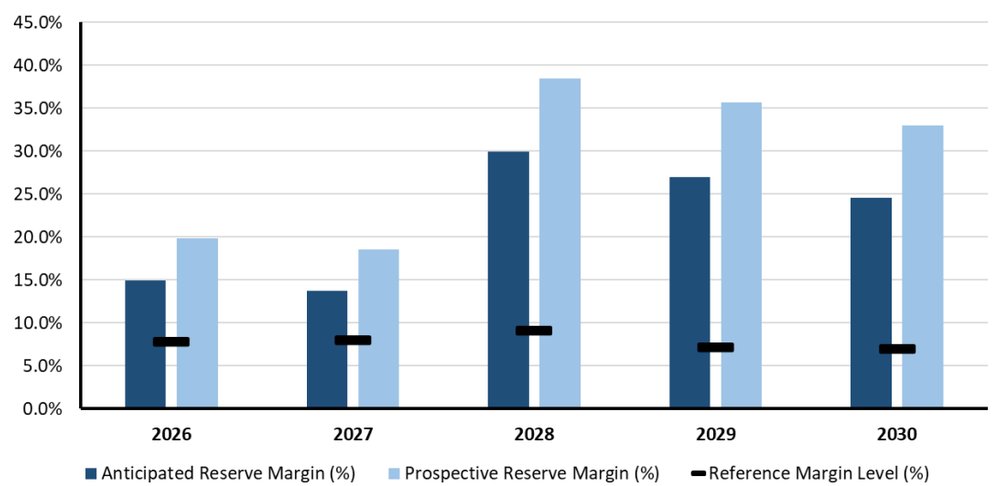


# WECC-Mexico

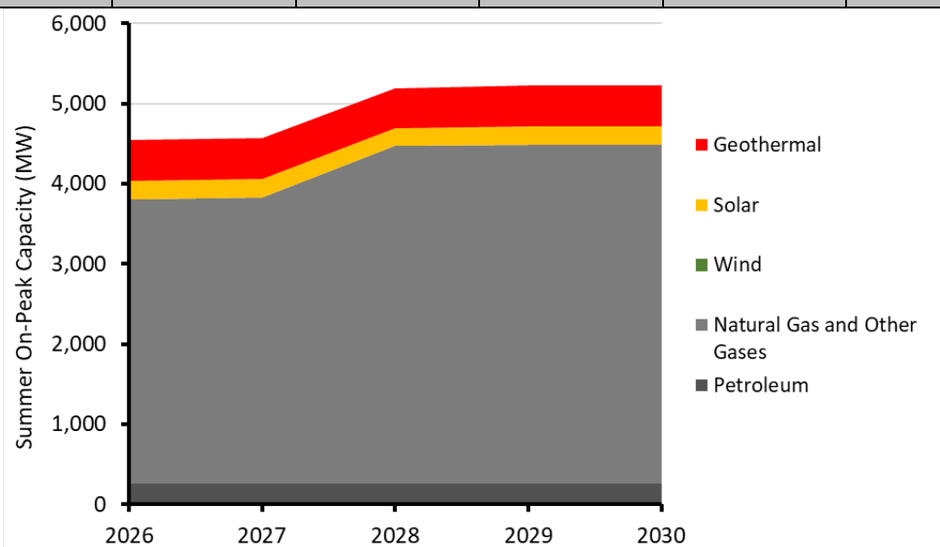
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 3,953 | 4,135 | 4,315 | 4,495 | 4,675 | 4,855 | 5,035 | 5,215 | 5,395 | 5,575 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Internal Demand | 3,953 | 4,135 | 4,315 | 4,495 | 4,675 | 4,855 | 5,035 | 5,215 | 5,395 | 5,575 |
| Additions: Tier 1 | 717 | 722 | 1,396 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 |
| Additions: Tier 2 | 196 | 198 | 367 | 392 | 392 | 392 | 392 | 367 | 392 | 392 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Capacity Transfers (WECC Model) | 0 | 131 | 410 | 482 | 600 | 600 | 600 | 600 | 600 | 600 |
| Existing-Certain and Net Transfers | 3,825 | 3,982 | 4,209 | 4,307 | 4,425 | 4,425 | 4,425 | 4,409 | 4,425 | 4,425 |
| Anticipated Reserve Margin (%) | 14.9% | 13.8% | 29.9% | 27.0% | 24.6% | 20.0% | 15.7% | 11.4% | 8.0% | 4.5% |
| Prospective Reserve Margin (%) | 19.9% | 18.6% | 38.4% | 35.7% | 33.0% | 28.1% | 23.5% | 18.4% | 15.2% | 11.5% |
| Reference Margin Level (%) | 7.8% | 8.0% | 9.1% | 7.2% | 7.0% | 6.8% | 6.7% | 7.4% | 6.4% | 6.3% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

| WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Coal | 0 | 0 | 0 | 0 | 0 |
| Petroleum | 259 | 261 | 258 | 259 | 259 |
| Natural Gas | 3,540 | 3,566 | 4,212 | 4,224 | 4,224 |
| Biomass | 0 | 0 | 0 | 0 | 0 |
| Solar | 229 | 231 | 214 | 229 | 229 |
| Wind | 7 | 5 | 6 | 7 | 7 |
| Geothermal | 506 | 510 | 505 | 506 | 506 |
| Conventional Hydro | 0 | 0 | 0 | 0 | 0 |
| Nuclear | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 |
| Battery | 0 | 0 | 0 | 0 | 0 |
| Total MW | 4,542 | 4,573 | 5,195 | 5,225 | 5,225 |

## WECC-Mexico Assessment

**Planning Reserve Margins**
The ARM is above the RML until 2035, the last year of the assessment period.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| **EUE (MWh)** | N/A | 0 | 0 |
| **NEUE (ppm)** | N/A | 0.00 | 0.00 |
| **LOLH (hours per Year)** | N/A | 0.00 | 0.00 |
| * No prior results as the assessment area is new for the *2025 LTRA*. | | | |

**Demand**
Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

**Generation**
Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

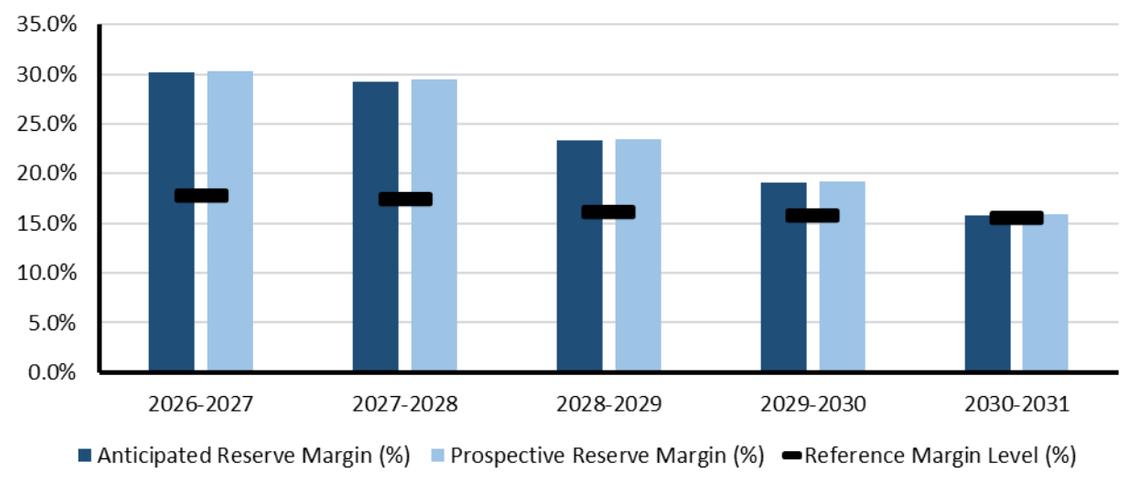


# WECC-Northwest

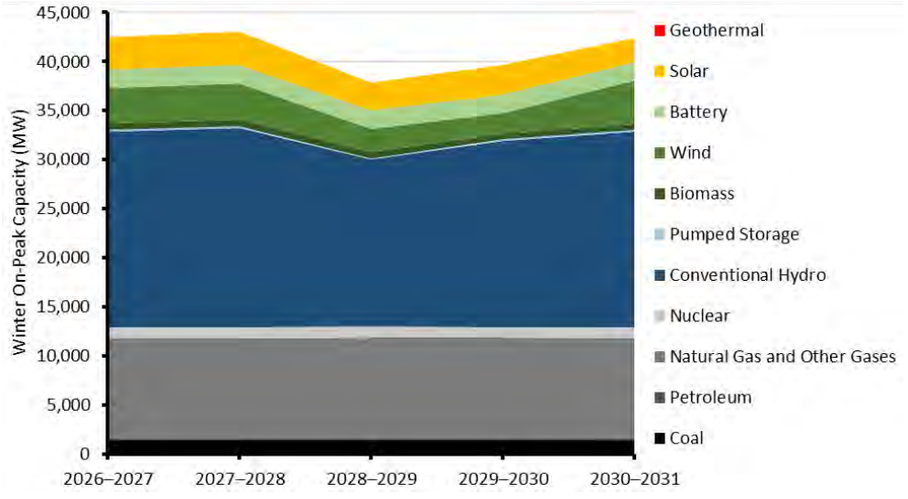
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 | 2031–2032 | 2032–2033 | 2033–2034 | 2034–2035 | 2035–2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 34,426 | 34,930 | 36,038 | 37,017 | 37,939 | 38,821 | 39,455 | 40,083 | 40,563 | 41,064 |
| Demand Response | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Net Internal Demand | 34,396 | 34,900 | 36,008 | 36,987 | 37,909 | 38,791 | 39,425 | 40,053 | 40,533 | 41,034 |
| Additions: Tier 1 | 3,463 | 3,463 | 3,219 | 3,219 | 3,219 | 3,219 | 3,463 | 3,232 | 3,221 | 3,217 |
| Additions: Tier 2 | 10 | 49 | 56 | 56 | 56 | 56 | 49 | 56 | 56 | 56 |
| Additions: Tier 3 | 697 | 830 | 939 | 4,958 | 5,389 | 5,605 | 6,267 | 5,963 | 5,921 | 5,903 |
| Net Capacity Transfers (WECC Model) | 7,242 | 7,630 | 7,316 | 7,066 | 6,896 | 6,825 | 6,825 | 6,825 | 6,630 | 5,841 |
| Existing-Certain and Net Transfers | 41,332 | 41,653 | 41,169 | 40,828 | 40,652 | 40,564 | 40,724 | 40,558 | 40,360 | 39,573 |
| Anticipated Reserve Margin (%) | 30.2% | 29.3% | 23.3% | 19.1% | 15.7% | 12.9% | 12.1% | 9.3% | 7.5% | 4.3% |
| Prospective Reserve Margin (%) | 30.3% | 29.4% | 23.4% | 19.2% | 15.9% | 13.0% | 12.2% | 9.5% | 7.7% | 4.4% |
| Reference Margin Level (%) | 17.8% | 17.4% | 16.1% | 15.8% | 15.5% | 15.3% | 15.9% | 15.0% | 14.9% | 14.8% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the WRAP Area Map.
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

| WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026–2027 | 2027–2028 | 2028–2029 | 2029–2030 | 2030–2031 |
| Coal | 1,516 | 1,516 | 1,475 | 1,475 | 1,475 |
| Petroleum | 97 | 97 | 95 | 95 | 95 |
| Natural Gas | 10,539 | 10,533 | 10,480 | 10,480 | 10,480 |
| Biomass | 657 | 617 | 615 | 536 | 536 |
| Solar | 1,545 | 1,544 | 1,622 | 1,622 | 1,622 |
| Wind | 2,149 | 2,149 | 1,319 | 1,311 | 1,311 |
| Geothermal | 4 | 4 | 4 | 4 | 4 |
| Conventional Hydro | 17,855 | 17,835 | 18,279 | 18,275 | 18,270 |
| Pumped Storage | 146 | 146 | 149 | 149 | 149 |
| Nuclear | 1,112 | 1,112 | 1,108 | 1,108 | 1,108 |
| Battery | 1,934 | 1,934 | 1,927 | 1,927 | 1,927 |
| Total MW | 37,553 | 37,486 | 37,072 | 36,981 | 36,976 |

## WECC-Northwest Assessment

### Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

### Non-Peak Hour Risk and Energy Assurance

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

### ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | N/A | 0 | 8,080 |
| NEUE (ppm) | N/A | 0 | 36.64 |
| LOLH (hours per Year) | N/A | 0 | 85.00 |
| * No prior results as the assessment area is new for the 2025 LTRA. | | | |

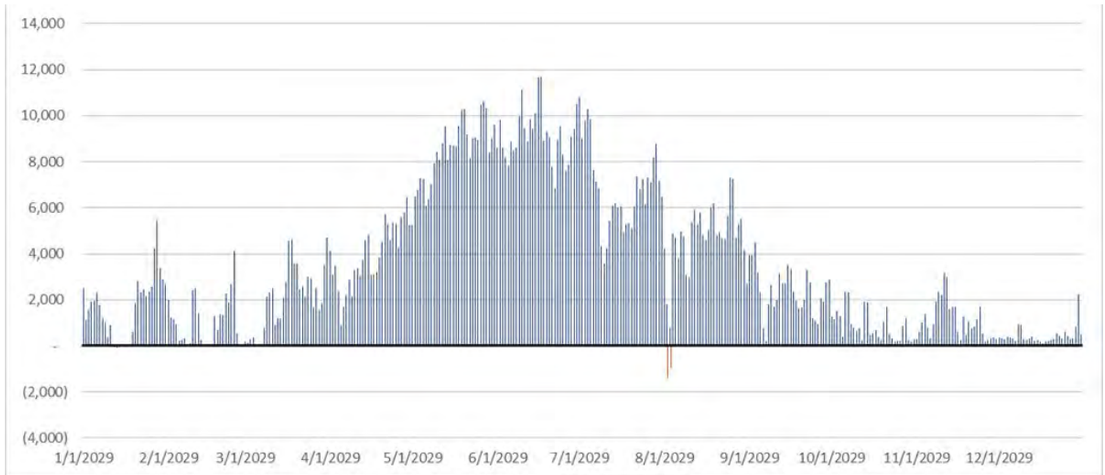
Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.

| Northwest - 2027 | Months | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing + Tier 1 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Hour Beginning 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| Northwest - 2029 | Months | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing + Tier 1 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Hour Beginning 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| 7 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 |
| 8 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| 9 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| 14 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| 15 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| 16 | 4 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 0 |
| 17 | 5 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 2 |
| 18 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 2 |
| 19 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 1 |
| 20 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 |
| 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

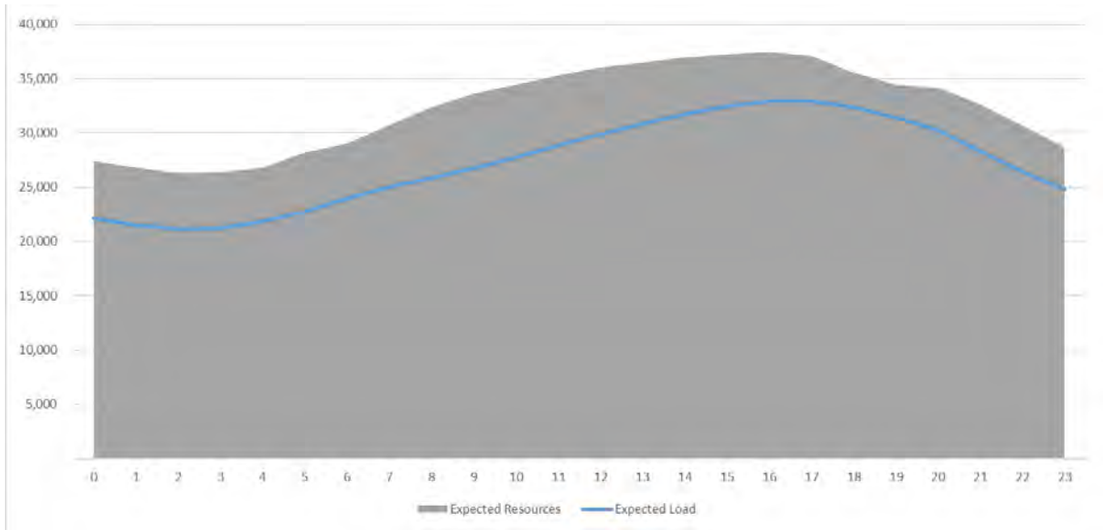
**Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029**

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest's excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.




**Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year**

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.




**Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year**

**Demand**

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

**Distributed Energy Resources**

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state's largest IOU has proposed a change that largely mirrors California's revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer's payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

**Generation**

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.
- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

**Transmission**: PacifiCorp's Blueprint transmission project will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

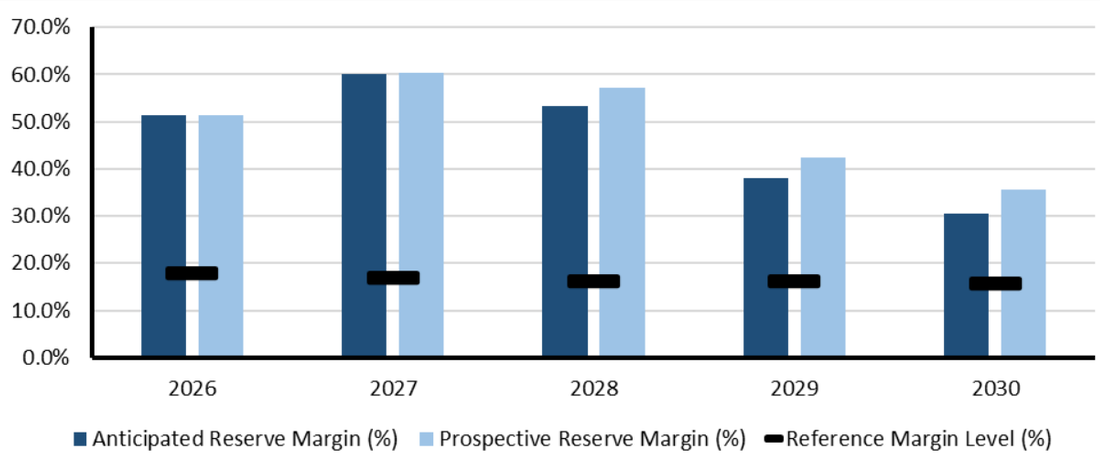


# WECC-Rocky Mountain

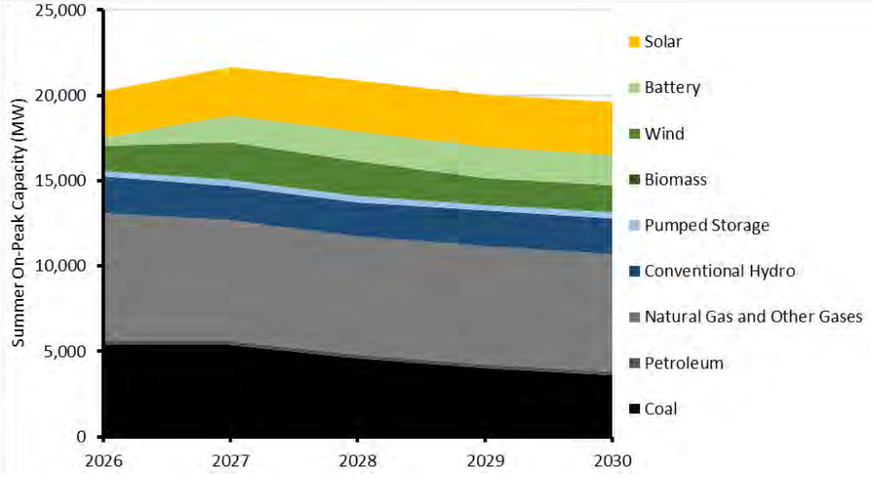
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 14,004 | 14,338 | 14,565 | 15,021 | 15,442 | 15,873 | 16,306 | 16,764 | 17,207 | 17,297 |
| Demand Response | 287 | 290 | 293 | 285 | 287 | 290 | 293 | 296 | 298 | 301 |
| Net Internal Demand | 13,717 | 14,048 | 14,272 | 14,736 | 15,154 | 15,583 | 16,013 | 16,468 | 16,909 | 16,997 |
| Additions: Tier 1 | 1,771 | 3,486 | 3,979 | 4,079 | 4,079 | 4,079 | 4,355 | 4,299 | 4,079 | 4,079 |
| Additions: Tier 2 | 0 | 45 | 585 | 640 | 761 | 761 | 810 | 810 | 761 | 761 |
| Additions: Tier 3 | 17 | 178 | 925 | 1,160 | 1,373 | 3,207 | 3,276 | 4,188 | 4,274 | 4,370 |
| Net Capacity Transfers (WECC Model) | 391 | 661 | 852 | 179 | 50 | 23 | 0 | 0 | 0 | 0 |
| Existing-Certain and Net Transfers | 18,979 | 18,995 | 17,884 | 16,278 | 15,696 | 14,882 | 14,721 | 14,329 | 14,143 | 14,098 |
| Anticipated Reserve Margin (%) | 51.3% | 60.0% | 53.2% | 38.1% | 30.5% | 21.7% | 19.1% | 13.1% | 7.8% | 6.9% |
| Prospective Reserve Margin (%) | 51.3% | 60.3% | 57.3% | 42.5% | 35.5% | 26.6% | 24.2% | 18.0% | 12.3% | 11.4% |
| Reference Margin Level (%) | 17.8% | 17.0% | 16.2% | 16.1% | 15.7% | 15.2% | 13.5% | 11.9% | 14.1% | 13.9% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

| WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | **2026** | **2027** | **2028** | **2029** | **2030** |
| Coal | 5,383 | 5,376 | 4,623 | 4,034 | 3,585 |
| Coal* | 5,053 | 5,376 | 4,429 | 3,379 | 2,180 |
| Petroleum | 204 | 204 | 204 | 204 | 204 |
| Natural Gas | 7,522 | 7,083 | 6,897 | 6,902 | 6,902 |
| Biomass | 6 | 6 | 6 | 3 | 3 |
| Solar | 2,695 | 2,873 | 3,002 | 3,071 | 3,071 |
| Wind | 1,437 | 2,218 | 2,054 | 1,555 | 1,550 |
| Conventional Hydro | 2,139 | 2,043 | 2,029 | 2,116 | 2,116 |
| Pumped Storage | 346 | 340 | 340 | 346 | 346 |
| Other | 126 | 126 | 126 | 126 | 126 |
| Battery | 496 | 1,547 | 1,726 | 1,817 | 1,817 |
| Unknown | 6 | 5 | 5 | 6 | 6 |
| Total MW | 20,359 | 21,820 | 21,011 | 20,178 | 19,725 |
| Total MW* | 20,029 | 21,820 | 20,817 | 19,523 | 18,320 |

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

## WECC-Rocky Mountain

**Planning Reserve Margins**
The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo's reserve margin is not used in WECC's methodology for the LTRA.

**Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments**
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

**ProbA Results**

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| EUE (MWh) | N/A | 0 | 0 |
| NEUE (ppm) | N/A | 0.00 | 0.00 |
| LOLH (hours per Year) | N/A | 0.00 | 0.00 |
| *No prior results as the assessment area is new for the 2025 LTRA. | | | |

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

**Demand**
Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

**Demand-Side Management**
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

**Distributed Energy Resources**
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

**Generation**
Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- **Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- **Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- **Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

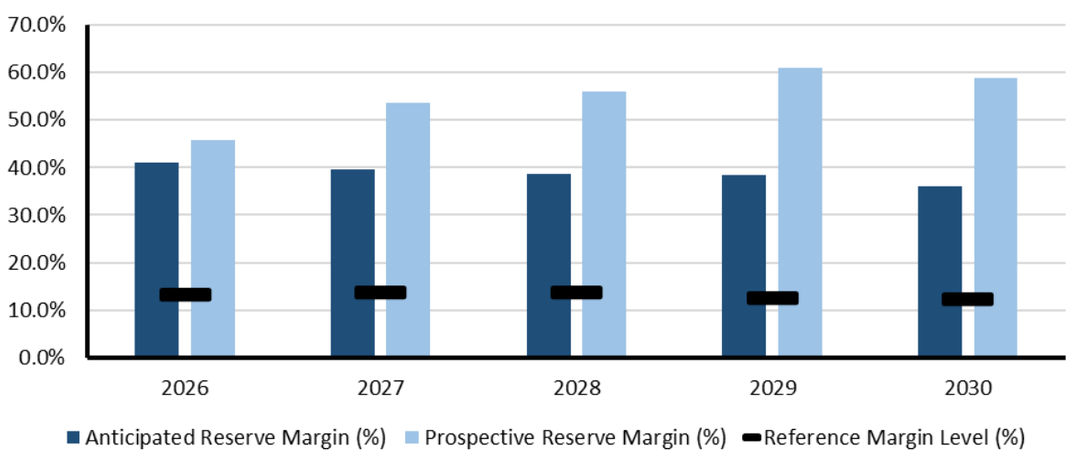


# WECC-Southwest

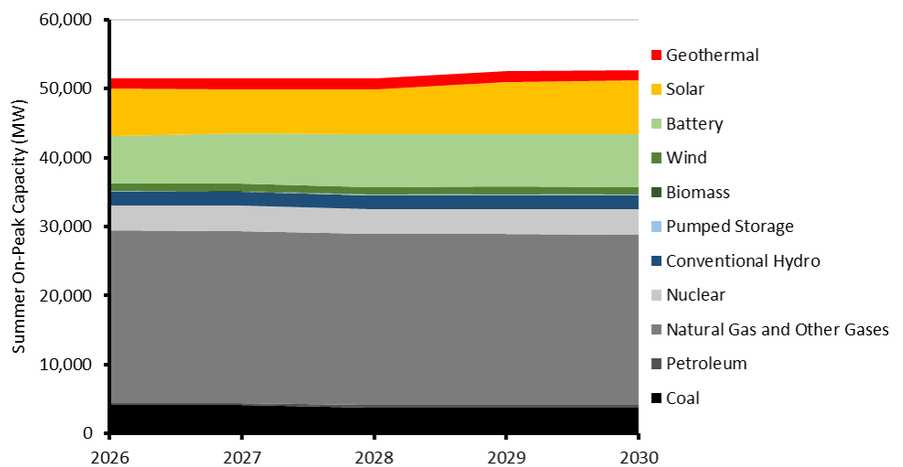
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 LTRA.*

## Demand, Resources, and Reserve Margins

| Quantity | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 37,407 | 38,911 | 40,429 | 41,887 | 43,551 | 44,772 | 45,664 | 46,317 | 47,226 | 47,988 |
| Demand Response | 237 | 258 | 264 | 272 | 282 | 237 | 258 | 264 | 272 | 282 |
| Net Internal Demand | 37,169 | 38,653 | 40,165 | 41,615 | 43,269 | 44,535 | 45,405 | 46,053 | 46,953 | 47,706 |
| Additions: Tier 1 | 6,639 | 7,501 | 8,155 | 8,562 | 8,914 | 8,914 | 8,914 | 8,396 | 8,852 | 8,852 |
| Additions: Tier 2 | 1,771 | 5,410 | 6,994 | 9,369 | 9,872 | 11,263 | 11,286 | 10,468 | 11,286 | 11,252 |
| Additions: Tier 3 | 2,502 | 3,899 | 5,242 | 7,562 | 9,710 | 12,409 | 14,804 | 14,801 | 24,521 | 24,571 |
| Net Capacity Transfers (WECC Model) | 902 | 2,544 | 4,162 | 5,101 | 6,301 | 5,895 | 5,570 | 4,880 | 5,030 | 4,715 |
| Existing-Certain and Net Transfers | 45,794 | 46,457 | 47,523 | 49,023 | 49,986 | 49,308 | 47,432 | 44,294 | 44,948 | 43,944 |
| Anticipated Reserve Margin (%) | 41.1% | 39.6% | 38.6% | 38.4% | 36.1% | 30.7% | 24.1% | 14.4% | 14.6% | 10.7% |
| Prospective Reserve Margin (%) | 45.8% | 53.6% | 56.0% | 60.9% | 58.9% | 56.0% | 49.0% | 37.1% | 38.6% | 34.3% |
| Reference Margin Level (%) | 13.3% | 13.7% | 13.6% | 12.6% | 12.2% | 12.0% | 11.7% | 12.3% | 11.3% | 11.1% |




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

| WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW) | | | | | |
|---|---|---|---|---|---|
| | 2026 | 2027 | 2028 | 2029 | 2030 |
| Coal | 4,121 | 4,116 | 3,749 | 3,754 | 3,754 |
| Coal* | 3,761 | 4,116 | 3,749 | 3,754 | 2,576 |
| Petroleum | 341 | 340 | 340 | 336 | 336 |
| Natural Gas | 24,978 | 24,887 | 24,817 | 24,837 | 24,750 |
| Biomass | 46 | 46 | 46 | 46 | 46 |
| Solar | 6,867 | 6,349 | 6,503 | 7,474 | 7,804 |
| Wind | 1,059 | 1,055 | 1,055 | 1,059 | 1,050 |
| Geothermal | 1,555 | 1,555 | 1,607 | 1,572 | 1,454 |
| Conventional Hydro | 1,984 | 1,989 | 1,989 | 1,982 | 1,981 |
| Pumped Storage | 113 | 113 | 113 | 113 | 113 |
| Nuclear | 3,641 | 3,640 | 3,640 | 3,641 | 3,641 |
| Battery | 6,824 | 7,325 | 7,657 | 7,671 | 7,671 |
| Total MW | 51,530 | 51,414 | 51,516 | 52,484 | 52,598 |
| Total MW* | 51,170 | 51,414 | 51,516 | 52,484 | 51,421 |
| ***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked. | | | | | |

## WECC-Southwest

**Planning Reserve Margins**
The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

**Energy Assessment, Including Non-Peak Hour Risk**
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

**ProbA Results**

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

| Base-Case Summary of Results | | | |
|---|---|---|---|
| | **2026*** | **2027** | **2029** |
| **EUE (MWh)** | N/A | 0 | 0 |
| **NEUE (ppm)** | N/A | 0.00 | 0.00 |
| **LOLH (hours per Year)** | N/A | 0.00 | 0.00 |
| * No prior results as the assessment area is new for the 2025 LTRA. | | | |

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

**Demand**
The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

**Demand-Side Management**
In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system's capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

**Distributed Energy Resources**
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

**Generation**
Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet**: A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

  Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.
- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, APS has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

# Demand Assumptions and Resource Categories

| Demand (Load Forecast) | |
|---|---|
| **Total Internal Demand** | This is the peak hourly load[49] for the summer and winter of each year.[50] Projected total internal demand is based on normal weather (50/50 distribution)[51] and includes the impacts of distributed resources, EE, and conservation programs. |
| **Net Internal Demand** | This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations. |

| Load Forecasting Assumptions by Assessment Area | | | |
|---|---|---|---|
| **Assessment Area** | **Peak Season** | **Coincident / Noncoincident[52]** | **Load Forecasting Entity** |
| MISO | Summer | Coincident | MISO LSEs |
| MRO-Manitoba Hydro | Winter | Coincident | Manitoba Hydro |
| MRO-SaskPower | Winter | Coincident | SaskPower |
| MRO-SPP | Summer | Noncoincident | SPP LSEs |
| NPCC-Maritimes | Winter | Noncoincident | Maritimes sub-areas |
| NPCC-New England | Summer | Coincident | ISO-NE |
| NPCC-New York | Summer | Coincident | NYISO |
| NPCC-Ontario | Summer | Coincident | IESO |
| NPCC-Québec | Winter | Coincident | Hydro-Québec |
| PJM | Summer | Coincident | PJM |
| SERC-East | Summer | Noncoincident | SERC LSEs |
| SERC-Florida Peninsula | Summer | Noncoincident | |
| SERC-Central | Summer | Noncoincident | |
| SERC-Southeast | Summer | Noncoincident | |
| Texas RE-ERCOT | Summer | Coincident | ERCOT |
| WECC-Alberta | Winter | Noncoincident | WECC BAs, aggregated by WECC |
| WECC-Basin | Summer | Noncoincident | |
| WECC-British Columbia | Winter | Noncoincident | |
| WECC-California | Summer | Noncoincident | |
| WECC-Mexico | Summer | Noncoincident | |

[49] Glossary of Terms Used in NERC Reliability Standards.
[50] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).
[51] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[52] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

| Load Forecasting Assumptions by Assessment Area | | | |
|---|---|---|---|
| **Assessment Area** | **Peak Season** | **Coincident / Noncoincident[52]** | **Load Forecasting Entity** |
| WECC-Northwest | Winter | Noncoincident | |
| WECC-Rocky Mountain | Summer | Noncoincident | |
| WECC-SW | Summer | Noncoincident | |

## Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

**Anticipated Resources[53]**

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[54]

**Prospective Resources**: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[55]

[53] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[54] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[55] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

## Resource Categories

**Generating Unit Status**: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[56]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[57]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[56] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[57] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

| Reserve Margin Descriptions |
| --- |
| **Planning Reserve Margins**: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile |
| **Anticipated Reserve Margin (ARM):** The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand |
| **Prospective Reserve Margin (PRM):** The amount of prospective resources less net internal demand calculated as a percentage of net internal demand |
| **Reference Margin Level (RML)**: The assumptions and naming convention of this metric vary by assessment area.<br><br>The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems. |

# Methods and Assumptions

## How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[58]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[59] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[60] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[61] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[62]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[58] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[59] BES Definition
[60] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[61] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[62] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

## How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

## Metrics for Probabilistic Evaluation Used in this Assessment

**Probabilistic Assessment**: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

**Loss-of-Load Hours:** LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

**Expected Unserved Energy:** EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[63] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

## Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.
Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
  - Planned (any of the following):
  - Permits have been approved to proceed

[63] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
  - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

## Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

| Reference Margin Levels for Each Assessment Area (2026–2030) | | | | | |
|---|---|---|---|---|---|
| **Assessment Area** | **Reference Margin Level** | **Assessment Area Terminology** | **Requirement?** | **Methodology** | **Reviewing or Approving Body** |
| MISO | 2025-2026<br>Summer: 8.1%<br>Fall: 14.9%<br>Winter: 19.1%<br>Spring (2027): 26.2% | Planning Reserve Margin | Yes: Established Annually[64] | 0.1 day/Year Loss of Load Expectation (LOLE) | MISO |
| MRO-Manitoba Hydro | 12.0% | Reference Margin Level | No | 0.1 day/Year LOLE | Reviewed by the Manitoba Public Utilities Board |
| MRO-SaskPower | 15.0% | Reference Margin Level | No | EUE and Deterministic Criteria | SaskPower |
| MRO-SPP | 19.0% | Resource Adequacy Requirement | Yes: studied on Biennial Basis | 0.1 day/Year LOLE | SPP Staff, Stakeholders, SPP Regional State Committee. |
| NPCC-Maritimes | 20.0%[65] | Reference Margin Level | No | 0.1 day/Year LOLE | Maritimes Sub-areas; NPCC |
| NPCC-New England | 13.0–13.4% | Installed Capacity Requirement | Yes: three year requirement established annually | 0.1 day/Year LOLE | ISO-NE, NPCC Criteria |
| NPCC-New York | 15.0%[66] | Installed Reserve Margin | Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources | 0.1 day/Year LOLE | NYSRC, NPCC Criteria |
| NPCC-Ontario | 15.8–22.6% | Reserve Margin Requirement | Yes: established annually for all years | 0.1 day/Year LOLE | IESO, NPCC Criteria |
| NPCC-Québec | 11.9–12.2% | Reference Margin Level | No: established Annually | 0.1 day/Year LOLE | Hydro-Québec, NPCC Reliability Coordinating Committee |
| PJM | 18.6–26.3% | Installed Reserve Margin | Yes: established Annually for each of three future years | 0.1 day/Year LOLE | PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard |
| SERC-Central | 15.0%[67] | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1 day/Year LOLE | Reviewed by Member Utilities |

[64] In MISO, the states can override the MISO PRM.

[65] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[66] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[67] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

| Reference Margin Levels for Each Assessment Area (2026–2030) | | | | | |
|---|---|---|---|---|---|
| **Assessment Area** | **Reference Margin Level** | **Assessment Area Terminology** | **Requirement?** | **Methodology** | **Reviewing or Approving Body** |
| SERC-East | 15.0%[68] | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1 day/Year LOLE | Reviewed by Member Utilities |
| SERC-Florida Peninsula | 15.0%[69] | Reliability Criterion | No: Guideline | 0.1 day/Year LOLP | Florida Public Service Commission |
| SERC-Southeast | 15.0%[70] | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1 day/Year LOLE | Reviewed by Member Utilities |
| Texas RE-ERCOT | 13.75% | Target Reserve Margin | No | 0.1 day/Year LOLE plus adjustent for non-modeled market considerations | ERCOT Board of Directors |
| WECC-Alberta | 11.6–17.6% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[71] |
| WECC-Basin | 12.3–14.0% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-British Columbia | 11.6–12.1% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-California[72] | 19.2–20.3% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-Mexico | 7.0–9.1% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-Northwest | 15.5–17.8% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-Rocky Mountain | 15.7–17.8% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |
| WECC-Southwest | 12.2–13.7% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC[58] |

[68] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[69] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[70] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[71] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[72] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

# Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

## LTRA Recommendations and Ongoing ERO Actions

**Add new resources with needed reliability attributes and make existing resources more dependable.**

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.

2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[73] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[74] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[75] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[76,77]

3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[78] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[79]

[73] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[74] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[75] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[76] NERC IBR Activities
[77] Order No. 901 Work Plan
[78] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[79] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

## LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[80]

| Initiative | Description | Product/Reliability Solution |
|---|---|---|
| **Cold Weather Reliability Standards and Activities** | Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans.<br><br>Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States* and respond to FERC directives.[81] In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information fillings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard's ability to address reliability concerns and inform potential future modifications. | Reliability Standards<br>NERC Alerts<br>Event Analysis Reports<br>Lessons Learned |
| **Inverter-Based Resources Strategy** | NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[82] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks.<br><br>NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements. | Reliability Standards<br>NERC Alerts<br>Reliability Guidelines<br>Event Analysis Reports<br>Lessons Learned<br>Educational Webinars |

[80] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[81] Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* and *Project 2024-03 Revisions to EOP-012-2* on NERC's standards development page. Project 2021-07

[82] IBR Activities

| LTRA Recommendations and Ongoing ERO Actions | | |
|---|---|---|
| | FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs.[83] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website. | |
| **Natural Gas-Electric Interdependence Initiatives** | Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[84] | Reliability Guideline |
| **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.**<br>1. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support. | | |
| **Initiative** | **Description** | **Product/Reliability Solution** |
| ***Interregional Transfer Capability Study* (ITCS)** | NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024[85]. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025.[86] See **Interregional Transfer Capability Study (ITCS) Canadian Analysis**. | ERO Study and Recommendations |

[83] FERC Order Issued November 17, 2022
[84] RSTC Approved Documents
[85] NERC's *Interregional Transfer Capability Study* (ITCS) Final Report
[86] NERC's *Interregional Transfer Capability Study (ITCS) Canadian Analysis* Final Report

## LTRA Recommendations and Ongoing ERO Actions

**Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.**

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

2. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

3. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [87]

4. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

5. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[88]

[87] NERC ERS Measure 6 Forward Tech Brief
[88] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

| LTRA Recommendations and Ongoing ERO Actions | | |
|---|---|---|
| **Initiative** | **Description** | **Product/Reliability Solution** |
| **Energy Assessments Initiatives** | NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2025 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed.<br><br>The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[89] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls.<br><br>New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[90]<br><br>In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[91] | Reliability Assessments<br>Reliability Standards |
| **Distributed Energy Resources Strategy** | NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[92] | Reliability Standards<br>Reliability Guidelines<br>Educational Webinars |
| **Strengthen relationships among reliability stakeholders.** | | |
| **Initiative** | **Description** | **Product/Reliability Solution** |
| **Ongoing Strategic Engagements** | NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels. | Constructive Partnerships |

[89] ERAWG
[90] Project 2022-03
[91] Project 2023-07
[92] DER Activities

# Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro's most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit XX: Department, Order No. 202-26-16 (Feb. 17, 2026)

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**Department of Energy**
Washington, DC 20585

**Order No. 202-26-16**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

*BACKGROUND*

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3 and 202-25-7, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, and November 19, 2025, respectively. Subsequently, Order No. 202-25-9, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until February 17, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods, which would help

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.
[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-9, at 3-7 (Nov. 18, 2025).

prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6] My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year . . . ."[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant

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[5] *See, e.g.*, *Id.* at 7-8.

[6] *See, e.g.*, *Id.* at 8.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025) (NERC 2025 Summer Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[8] *Id*.

[9] EIA, *Michigan State Profile and Energy Estimates* (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[10] *Id*.

[11] L.A. Times, *Nuclear plants face decadelong timeline to meet AI energy needs* (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC still anticipates "elevated risk of operating reserve shortfalls."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

*CONTINUING EMERGENCY CONDITIONS*

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, from June 2025 through December 2025,[17] the Campbell plant has generated an average of approximately 561,100 MWh per month, providing vital generation capacity to the region. From June 11, 2025 through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response

[12] NERC 2025 Summer Reliability Assessment at 16.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025– 2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id*. at 2. For further information regarding the determination that emergency conditions existed, *see Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (Aug. 20, 2025).

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1, n.1.

[17] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to only include the J.H. Campbell Plant.).

to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[18] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[19] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[20]

In December of 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[21] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[22] MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[23]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[24] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

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[18] MISO, *Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct*, FERC Docket No. ER22-495-000 (Nov. 30, 2021) (MISO Transmittal Letter). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[19] MISO Transmittal Letter at 3.

[20] *Id.* at 3-4.

[21] MISO, *Attributes Roadmap* (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[22] *Id.* at 11.

[23] *Id.*

[24] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[25]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[26] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[27] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[28] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[29] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[30] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[31] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[32]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[33] These findings were echoed in NERC's 2024 – 2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the

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[25] *Id.* at 12.

[26] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[27] *Id.* at 7.

[28] *Id.* at 8.

[29] *Id.* at 43.

[30] *Id.* at 15.

[31] *Id*.

[32] *Id*.

[33] NERC, 2023–2024 Winter Reliability Assessment, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[34]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[35]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

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[34] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[35] *See* MISO Notifications Overview, *Real-Time Operations*, https://www.misoenergy.org/markets-and-operations/notifications/.

[36] MISO 2025 – 2026 Planning Resource Auction at 13.

[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation70 2311.pdf.

[38] *Id.* at 2.

[39] *Id.* at 7.

[40] *Id.* at 9.

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025,[43] and the ERAS should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[44] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[45] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary

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[41] *Id.* at 7, 9.

[42] *Id*.

[43] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

threat to our Nation's economy, national security, and foreign policy."[46] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[47] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[48]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[49] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[50] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[51]

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[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id*.

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[49] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/.

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[54]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

## *ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[55] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcommittee on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[53] *Id.* at 6.

[54] *Id.* at 7.

[55] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation until May 18, 2026.[56]

Based on my determination of an emergency set forth above, I hereby order:

A. From February 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By March 4, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

[56] 16 U.S.C. § 824a(c)(4).

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective on February 17, 2026, through May 18, 2026, with the exception of applicable compliance obligations in paragraph D.

Chris Wright

Chris Wright
Secretary of Energy

cc:

**FERC Commissioners**

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Michigan Public Service Commissioners**

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit YY: Department, Order No. 202-26-17 (Feb. 23, 2026)

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**Department of Energy**
Washington, DC 20585

**Order No. 202-26-17**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

*BACKGROUND*

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04 and 202-25-08, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain in operation for 90 days, until August 28, 2025, and November 26, 2025, respectively. Subsequently, Order No. 202-25-10, issued pursuant to FPA section 202(c), required the Eddystone Units to remain in operation for 90 days, until February 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.[5] My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g., PJM Interconnection, L.L.C. and Constellation Energy Corp.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).
[4] *See, e.g., id.*
[5] *See, e.g., id.* at 8, Ordering Paragraph A.

dispatchable resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

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[6] *Keeping the Lights On: Examining the State of Regional Reliability: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy & Com.*, 119th Cong., at 4-5 (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id*. *See also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] PJM Inside Lines, *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk* (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, at 1 (Feb. 24, 2023) (Four Rs Report).

[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

*CONTINUING EMERGENCY CONDITIONS*

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 continue, both in the near and long term.[11] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency, the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,[12] providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[13]

PJM's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 – February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/ Load Management Alert and an EEA 1.[14] Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[15] The Department granted PJM's application and issued Order No. 202-26-02 on

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[11] Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. If Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

[12] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> *"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to include only the Eddystone Generating Station.

[13] *See* PJM, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[14] *See id.* (search range set to: effective from 01/20/2026 until 02/07/2026).

[15] PJM, *Request for Emergency Order Under Federal Power Act, Section 202(c)*, at 2 (Jan. 24, 2026), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

January 25, 2026.[16] On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was granted by the Department on the same day.[17]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[18] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[19] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[20]

The evidence indicates that there is also a potential longer term resource adequacy emergency in the PJM region. In a news release expressing support for Order No. 202-25-04, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[21]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[22] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for

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[16] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[17] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[18] PJM Inside Lines, *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand* (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[19] PJM Inside Lines, *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand* (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[20] PJM Resource Adequacy Planning Special Planning Committee, *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[21] PJM Inside Lines, *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30* (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id.*

[22] Four Rs Report at 2.

renewable projects is approximately 5%.[23] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[24] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[25]

In its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[26] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[27] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers," and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[28] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[29] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[30]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[31] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[32]

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[23] *Id.*

[24] *Id.* at 16, Table 1.

[25] *Id.*

[26] PJM, *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712, at 10 (Dec. 13, 2024).

[27] *Id.*

[28] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[29] *Id.* at 14.

[30] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").

[31] Affidavit of Mr. Donald Bielak at P 10.

[32] *Id.* at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[33] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[34]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observes that the PJM region is at high risk of energy shortfalls over the next five years[35] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[36] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;" however "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[37] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[38]

Order Nos. 202-25-04, 202-25-08, and 202-25-10 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our nation's economy, national security, and foreign policy."[39] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international

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[33] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

[34] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[35] NERC, *2025 Long-Term Reliability Assessment*, at 7, Figure 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[36] *Id.* at 8.

[37] *Id.* at 16.

[38] *Id.* at 91.

[39] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

commodity markets."[40] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[41]

Further, the Department detailed the myriad challenges affecting the nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[42] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[43] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[44] In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[45] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[46]

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[40] *Id*.

[41] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[42] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025) (Resource Adequacy Report), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[43] *See* PPL Corporation, *PPL Corporation Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINA L.pdf.

[44] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[45] Resource Adequacy Report at 28.

[46] *Id.* at 27.

Grid operators, including PJM, have likewise acknowledged the nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[47] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[48] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[49] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[50]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

## *ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[51] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[47] Asthana Test. at 4.

[48] *Id.*

[49] *Id.* at 9-10.

[50] *Id.* at 10.

[51] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain in operation through May 24, 2026.[52]

Based on my determination of an emergency set forth above, I hereby order:

A. From February 24, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By March 11, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this

[52] 16 U.S.C. § 824a(c)(4).

Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

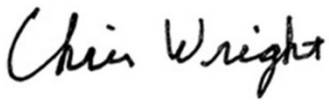
E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective on February 24, 2026, through May 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of February 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Pennsylvania Public Utility Commissioners**
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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|---|---|---|
| Federal Power Act Section 202(c)<br>Emergency Order: Craig Unit 1 | )<br>)<br>)<br>) | Order No. 202-26-49 |

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

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Exhibit ZZ: Department, Order No. 202-26-18 (Mar. 16, 2026)

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**Department of Energy**
Washington, DC 20585

**Order No. 202-26-18**

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

## *BACKGROUND*

TransAlta Centralia Generation ("Centralia") is an electric generating facility in Centralia, Washington. Centralia is owned and operated by the TransAlta Centralia Generation LLC ("TransAlta"). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[3] Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 was slated to cease operation in December 2025 based on a 2011 Washington law[4] and a subsequent agreement between TransAlta and the State of Washington.[5] TransAlta has announced plans to convert the unit to natural gas by 2028.[6]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data (2024)* (2024 Form EIA-860), (September 09, 2025), https://www.eia.gov/electricity/data/eia860/.

[4] Act of Apr. 29, 2011, Ch. 180, 2011 Wash. Laws, https://leg.wa.gov/CodeReviser/documents/sessionlaw/2011pam4.pdf.

[5] *See* MOA (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to MOA (July 13, 2017), https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf. As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. Those orders were based on my determination that emergency conditions existed in the WECC Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.

Specifically, I determined that the WECC Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.[7] I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[8] I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.[9] My determination was based on a number of facts.

First, in its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[10] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year."[11]

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[12] and that "[l]oad growth and retirements mean the region faces a

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would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[6] TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

[7] *See, e.g.*, *TransAlta*, Order No. 202-25-11, at 1 (Dec. 16, 2025).

[8] *See, e.g.*, *id.* at 1-3.

[9] *See, e.g.*, *id.* at 3-4.

[10] NERC, *2025-2026 Winter Reliability Assessment*, at 6 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[11] *Id.*

[12] E3, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, at 2 (Sept. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20

power supply shortfall in 2026."[13] E3 reported that nearly 9000 MW of new capacity will be needed in the region by 2030, but currently only 3000 MW of projects for new capacity are in active development.[14] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[15]

*EMERGENCY SITUATION*

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11 and 202-25-11B continue, both in the near and long term.[16] The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC Northwest region. According to the U.S. Environmental Protection Agency's data, in 2025,[17] Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[18] NERC assessed that the WECC Northwest region is at high risk of energy shortfalls over the next five years,[19] noting that "[r]apid forecasted demand growth is driving the need for more resources" and that "[p]eriods of unserved energy are projected for both summer and winter."[20] The assessment notes that peak load in the region "is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest."[21] Additionally, while over 10 GW of new variable resources are in development, the assessment warns that "additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging."[22]

On February 25, 2026, a preliminary injunction was issued by the United States District Court for the District of Oregon that imposes operational constraints on the dams

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WA%20RA%20Meeting.pdf. *See also id.* for the list of E3's study sponsors, which include certain "regional utilities and generation owners."

[13] *Id*. at 10.

[14] *Id*.

[15] *Id*. at 2.

[16] *See, e.g.*, Order No. 202-25-11 at 1.

[17] *See Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "January, February, March, April, May, June, July, August, September, October, November, December." The data can then be filtered to only include the Centralia).

[18] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[19] *Id.* at 7.

[20] *Id.* at 8.

[21] *Id.* at 19.

[22] *Id.* at 19.

that comprise the Federal Columbia River Power System.[23] The restrictions imposed by the preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC Northwest assessment region.[24] The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.[25] BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.[26] Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.[27]

Order Nos. 202-25-11 and 202-25-11B were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[28] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[29] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid

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[23] *National Wildlife Federation, et al. (NWF) v. National Marine Fisheries Service, et. al. (NMFS)*, case 3:01-cv-00640 (D. Or. Feb. 25, 2026) (order granting preliminary injunction).

[24] Fed. Def. Response to Minute Order at 4-5, *NWF v. NMFS, et. al.*, case 3:01-cv-00640 (D. Or. Feb. 24, 2026).

[25] *See, e.g.*, Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2582.

[26] *See* Dibble Decl. ¶ 28; ¶ 42, fig. 3.

[27] *See*, e.g., Dibble Decl. ¶ 26; Stevenson Decl. ¶ 18.

[28] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[29] *Id.*

technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[30]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[31] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

## *ORDER*

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[32] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Centralia Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

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[30] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[31] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[32] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through June 14, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From March 17, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)[33] or Southwest Power Pool Western RC[34] (in its role as the Reliability Coordinator). Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By March 31, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order. TransAlta shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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[33] *See* EIA-930A 2024 Data, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930A 2024 SCH 2, the BA Code for TransAlta Central Generation is GRID. *See* EIA-930 data reference tables, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930 data reference tables BA Code GRID is associated with Gridforce Energy Management, LLC.

[34] *See* Southwest Power Pool RTO and Western RC Footprint with Planned Expansion map, https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png.

E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from March 17, 2026 through June 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 16th day of March 2026.

Chris Wright
_____
Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

**Washington Utilities and Transportation Commission**
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl