BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-136:
Sierra Club v. BNSF Ry. Co. Consent Decree

THE HONORABLE JOHN C. COUGHENOUR

UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF WASHINGTON
AT SEATTLE

SIERRA CLUB, *et al.*, Plaintiffs, v. BNSF RAILWAY COMPANY, Defendant.	CASE NO. C13-0967-JCC CONSENT DECREE

This matter comes before the Court on the parties' motion to enter their proposed consent decree (Dkt. No. 374). The United States has no objection to entry of the proposed consent decree. (Dkt. No. 383.) Having thoroughly considered the motion and the relevant record, the Court hereby GRANTS the motion and ENTERS the following consent decree:

WHEREAS, Plaintiffs Sierra Club, Puget Soundkeeper Alliance, RE Sources for Sustainable Communities, Columbia Riverkeeper, Friends of the Columbia Gorge, Spokane Riverkeeper, and Natural Resources Defense Council (collectively, Plaintiffs) filed a complaint in this Court seeking civil penalties, as well as declaratory and injunctive relief, against Defendant BNSF Railway Company (BNSF and collectively with Plaintiffs, the Parties) and others on June 4, 2013, alleging violations of the Clean Water Act, 33 U.S.C. § 1251, *et seq.*, (the CWA or the Act);

WHEREAS, Plaintiffs filed a separate complaint in the United States District Court for the Eastern District of Washington similarly alleging that BNSF and others had violated the CWA (assigned Civil No. 2:13-cv-00272 (E.D. Wash.) and hereafter referred to as the Eastern District Action);

WHEREAS, the Eastern District Action was transferred to this Court and assigned Civil No. 2:14-cv-00660, after which it was consolidated with the above-captioned civil action (Dkt. No. 84) (the Litigation);

WHEREAS, subsequent to consolidation, on May 6, 2015, Plaintiffs filed their third amended complaint (Dkt. No. 113) naming only BNSF as a Defendant;

WHEREAS, prior to filing their initial complaint, Plaintiffs sent to BNSF and others Notices of Intent to Sue dated April 2, 2013, and May 9, 2013, in which they stated their intent to assert claims for alleged violations of CWA sections 301 and 404, 33 U.S.C. §§ 1311, 1344, and the Rivers and Harbors Act of 1899, 33 U.S.C. § 403, *et seq*., and further asserted that "[t]he pollutants that the Dischargers have discharged, are discharging, and will continue to discharge include, but are not limited to, coal, coal chunks, coal dust, metabolites or related byproducts of coal, surfactants applied to the coal, coal chunks and coal dust, petcoke, petcoke chunks, petcoke dust, and suppressants";

WHEREAS, CWA Section 301(a), 33 U.S.C. § 1311(a), prohibits the unpermitted discharge of any pollutant to waters of the United States;

WHEREAS, Plaintiffs brought their action against BNSF for alleged CWA violations pursuant to Section 505 of the Act, 33 U.S.C. § 1365;

WHEREAS, BNSF is a Class I railroad operating in 28 states. BNSF transports freight, including a number of commodities, for a wide range of customers. As a Class I railroad, BNSF operates as a common carrier subject to the jurisdiction of the Surface Transportation Board (STB). BNSF's status as a common carrier requires the railroad to provide transportation of goods on reasonable request;

WHEREAS, coal and petroleum coke (petcoke) are among the commodities that BNSF transports for its customers. BNSF transports coal, petcoke, and other commodities in open-top railcars in the State of Washington and several other states;

WHEREAS, Paragraph 48 of Plaintiffs' third amended complaint alleges that "[e]ach and every coal train and each and every rail car carrying coal discharges coal pollutants to waters of the United States when traveling adjacent to, over, and in proximity to waters of the United States." Paragraph 3 of the third amended complaint defines "coal pollutants" to include "coal, coal chunks, coal dust, metabolites or related byproducts of coal, and other substances or materials added to the coal including, but not limited to, surfactants and suppressants, and petroleum coke." The third amended complaint further alleges that BNSF did not obtain any permit to discharge any pollutants from its railcars;

WHEREAS, BNSF asserted defenses to the allegations contained in the third amended complaint, expressly denies Plaintiffs' allegations in their entirety, and admits no liability by entering this Consent Decree;

WHEREAS, the Parties recognize that this Consent Decree is a settlement of a contested matter;

WHEREAS, the objective of the Parties in entering this Consent Decree is to resolve the Litigation; and

WHEREAS, the Parties acknowledge that this Consent Decree has been negotiated by the Parties in good faith and will avoid further litigation, and the Court, in entering this Consent Decree, finds that this Decree is fair, reasonable, and in the public interest.

NOW, THEREFORE, without the admission of any issue of fact or law except as provided in Section I, and with the consent of the Parties,

IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. GENERAL PROVISIONS

1. Jurisdiction and Venue. This Court has jurisdiction over the subject matter of this action

and the Parties pursuant to 28 U.S.C. § 1331 and 33 U.S.C. § 1365(a). Venue is proper in this judicial district pursuant to section 505(c) of the Act, 33 U.S.C. § 1365(c), because the complaint alleges that discharges in violation of the Act occurred in this judicial district. BNSF does not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree.

2. Retention of Jurisdiction. This Court shall retain jurisdiction for the purposes of issuing such further orders and directions as may be necessary and appropriate for the implementation or modification of this Consent Decree, enforcing compliance with, or resolving disputes regarding the provisions of this Consent Decree.

3. Reservation of Rights. The Parties reserve the right to enforce the terms of this Consent Decree and take any action authorized by federal or state law not inconsistent with this Consent Decree.

4. Parties Bound. This Consent Decree shall be binding upon Plaintiffs, BNSF, and their respective officers, agents, servants, employees, successors, and assigns.

5. Counterparts. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

6. DOJ and EPA Review. The Parties recognize that, under 33. U.S.C. § 1365(c)(3), this Consent Decree can be entered only forty-five (45) days after the Attorney General of the United States and the Administrator of the Environmental Protection Agency receive a copy of this proposed Consent Decree. Plaintiffs shall serve copies of the executed Consent Decree upon the Administrator of the United States Environmental Protection Agency, the Attorney General, and the Regional Administrator for EPA Region 10, and Plaintiffs shall provide notice to the Court of the foregoing requirements, as required pursuant to 40 C.F.R. § 135.5.

7. Final Judgment. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final, non-appealable judgment of the Court under Rules 54

and 58 of the Federal Rules of Civil Procedure.

II. CAR COVER STUDY

8. BNSF shall conduct a study to assess the commercial and operational feasibility of car covers for use on open-top coal and petcoke railcars (the Car Cover Study). In its sole discretion, BNSF may conduct this study in cooperation with various interested stakeholders, including without limitation, the Association of American Railroads, its customers, mine operators located in the Powder River Basin, or others invited by BNSF, to the extent they may agree to participate. It is anticipated that the Car Cover Study will occur over a period of approximately two years following entry of this Consent Decree.

9. BNSF's obligation to conduct the Car Cover Study under Paragraph 8 shall require BNSF to assess only car cover designs for which a functioning prototype is reasonably available to BNSF within six months of the date of entry of this Consent Decree. As part of the first phase of the Car Cover Study, BNSF shall conduct outreach and solicit participation from car cover manufacturers.

10. This Consent Decree shall not be construed to require BNSF to assess any conceptual car cover design or develop any car cover design. As between the Parties, BNSF is exclusively responsible for conducting and overseeing the Car Cover Study, as well as arranging for equipment and personnel.

11. Once during each six-month period (January–June and July–December of each year) until the conclusion of the Car Cover Study, BNSF shall provide to Plaintiffs electronic copies of final versions of all reports, technical specifications of car cover designs, testing results, testing procedures, and testing data created for the Car Cover Study. Prior to receiving any such information pursuant to this Paragraph, each Plaintiff organization shall execute a confidentiality agreement acceptable to all study participants, including without limitation any companies whose covers will be assessed. Plaintiffs acknowledge that BNSF reserves the right to redact cover manufacturer-, customer-, mine- and utility-specific information in any document provided

pursuant to this Paragraph, and Plaintiffs agree that the redaction of such information shall not be a basis for challenging the adequacy of BNSF's compliance with this Paragraph. In the event that Plaintiffs contend that any information redacted by BNSF prevents Plaintiffs from assessing compliance with this Consent Decree, Plaintiffs may invoke the Dispute Resolution provisions in Section VIII to contest the necessity for such redactions.

12. If, in its sole discretion, BNSF determines that any car cover design assessed under Paragraph 8 is commercially and operationally feasible, then BNSF shall undertake good faith efforts to amend the safe harbor provision of BNSF Price List 6041-B (the Coal Loading Rule) to add such car cover design(s) within 90 days of the conclusion of the car cover study. A decision by the STB concluding that any amendment to the Coal Loading Rule proposed pursuant to this Paragraph is unreasonable or otherwise invalid shall not constitute the basis for any allegation that BNSF has not complied with its obligations under this Consent Decree.

13. For the purpose of Section II, commercial and operational feasibility of a car cover design shall mean that a particular car cover (a) when used during loading and unloading operations, and in transit, poses no unreasonable risk of property damage or of bodily harm to BNSF employees, employees of any shipper for which BNSF transports coal and/or petcoke, employees of any mine, or to the general public; (b) can be physically attached to existing open-top railcars transported by BNSF without unreasonable modification to such railcars, (c) will function properly and as intended throughout all operational conditions encountered by BNSF trains while in-transit, (d) complies with all applicable regulatory requirements and industry equipment and interchange rules, (e) conforms to all applicable BNSF clearance and operational requirements, (f) requires no unreasonable modifications to equipment or processes used in loading or unloading coal and petcoke into or out of railcars, (g) would not be unreasonably expensive to procure, install, operate, replace, repair, or maintain; and (h) otherwise meets the requirements of the Coal Loading Rule. Notwithstanding any such determination of commercial and operational feasibility by BNSF, mines, shippers, or any other entity providing rail cars

cannot be required by BNSF to adopt or accept any specific railcar covers or associated modifications to equipment or loading or unloading processes.

14. In the event that BNSF determines in its sole discretion that there exists one or more car cover design that is commercially and operationally feasible under Section II, BNSF shall present the results of the Car Cover Study at the following rail transportation and coal industry meetings or conferences during the two-year period following the conclusion of the Car Cover Study: American Railway Engineering and Maintenance of Way Association meetings, the National Coal Transportation Association meetings, and the Railroad Environmental Conference. BNSF shall provide Plaintiffs with copies of any materials that BNSF uses to present the results of the Car Cover Study at those events.

III. REMOVAL

15. BNSF shall remove significant accumulations of coal and/or petcoke materials in areas on or adjacent to BNSF's right-of-way at each of the locations identified in Appendix A to this Consent Decree, as identified at trial and in designated deposition testimony. BNSF shall complete this initial removal of accumulations of coal and/or petcoke materials from each of these locations no later than one (1) year from entry of this Consent Decree.

16. Within thirty (30) business days of completion of the removal of coal and/or petcoke material at each site required by Paragraph 15, BNSF shall notify Plaintiffs that the removal is complete. The notification shall include before and after photographs and other documentation reasonably necessary to demonstrate that BNSF has removed materials consistent with Paragraph 15.

17. BNSF shall conduct follow-up inspections of each area identified in Appendix A two times during the period of this Consent Decree. BNSF will use good faith efforts to conduct the first inspection between 9–12 months after service of the notification required by Paragraph 16, and the second 9–12 months after the preceding inspection, subject to the availability of sufficient track windows, and taking into consideration weather, safety, and other factors that

could restrict the time available to conduct an inspection. Within thirty (30) days of each inspection, BNSF shall provide Plaintiffs with a statement as to whether any significant accumulations of coal and/or petcoke materials require removal consistent with Paragraph 16.

18. In the event that BNSF identifies significant accumulations of coal and/or petcoke materials in areas on or adjacent to BNSF's property during either of the two subsequent inspections required by Paragraph 17, BNSF shall remove such materials in the same manner as in Paragraph 15. Within thirty (30) days of completion of any additional removal required by this Paragraph, BNSF shall notify Plaintiffs in writing that this additional removal is complete. The notification shall include photographs or other documentation reasonably necessary to demonstrate that BNSF has complied with its obligations under this Paragraph.

19. BNSF's obligation to remove significant accumulations of coal and/or petcoke material under Paragraphs 15 and 18 shall be limited to material on land. BNSF is only required to use non-invasive methods or techniques (e.g., vacuuming) to conduct the removal, and the means and methods to conduct the removal required under Section III are within BNSF's sole discretion. In no event shall BNSF be required under this Consent Decree to conduct any removal activities in any waterway, including any water of the United States, or conduct any ballast or track maintenance activities to remove materials from BNSF track, nor shall BNSF be obligated to remove non-significant accumulations or scattered, individual pieces or fragments of coal and/or petcoke material. BNSF shall not be required through this Consent Decree to remove coal and/or petcoke materials under Paragraphs 15 or 18 from any property in the event that any property owner declines to allow BNSF or its contractors access to their property under reasonable conditions.

20. In the event that Plaintiffs disagree with any determination that (a) BNSF has completed removal of significant accumulations of coal and/or petcoke material at any location under Paragraphs 15 and 18, (b) any subsequent inspection pursuant to Paragraph 17 identified no new and significant accumulations of coal and/or petcoke material that require removal, or (c) BNSF

has completed any subsequent removal of significant accumulations of coal and/or petcoke material required under Paragraph 18, Plaintiffs may invoke the Dispute Resolution procedures in Section VIII.

IV. SUPPLEMENTAL ENVIRONMENTAL PROJECTS

21. Within 30 days of the date this Consent Decree is approved by the Court, BNSF shall pay $1,000,000 to The Rose Foundation for Communities and the Environment for projects to improve water quality or habitat in the State of Washington (and, to the extent they may improve habitat or water quality of the Columbia River, in the State of Oregon). (*See* Dkt. No. 374-1.) Such payment shall be made by check payable and mailed to The Rose Foundation for Communities and the Environment, Attention: Tim Little, 1970 Broadway, Suite 600, Oakland, California 94612, and shall bear the notation "Sierra Club, et al. v. BNSF Railway Co., Clean Water Act Settlement," with a copy provided to Plaintiffs at the time payment is made.

V. RELEASE AND COVENANT NOT TO SUE

22. Plaintiffs release BNSF for all claims that were or could have been brought in this litigation.

23. Plaintiffs covenant not to sue BNSF system-wide under the Clean Water Act or analogous state law or any common law theory on the theory of material leaving open-top rail cars and entering waters of the United States or waters of any state for any events or occurrences arising over the next five (5) years.

24. Any information provided by BNSF to Plaintiffs pursuant to this Consent Decree shall not be admissible in any proceeding against BNSF or any entity that meaningfully participates in the Car Cover Study (as that term is defined in Section II). Notwithstanding the previous sentence, information provided by BNSF to Plaintiffs pursuant to this Consent Decree may be used in proceedings to enforce the terms of this Consent Decree.

25. If the Consent Decree is terminated prior to five (5) years from the date of entry of the Consent Decree, the provisions of Paragraphs 23 and 24 shall survive for the remainder of the

five (5) year term of the covenant not to sue.

26. The Parties agree that, as of the date of the entry of this Consent Decree, litigation is not "reasonably foreseeable" concerning the matters described in the third amended complaint. To the extent that any Party previously implemented a litigation hold to preserve documents or electronically stored information related to the Litigation, the Party is no longer required to maintain such litigation hold. Nothing in this paragraph relieves any Party of any other obligations imposed by this Consent Decree or of the obligation to implement a litigation hold concerning the rights, obligations, and duties set forth in this Consent Decree.

VI. ATTORNEY FEES AND COSTS

27. By entering into this Consent Decree, BNSF in no way acknowledges or concedes that Plaintiffs are entitled to recover any costs of litigation (including attorney fees or expert witness fees).

28. Notwithstanding Local Civil Rule 54, within sixty (60) days of entry of this Consent Decree, Plaintiffs may file with the Court a petition under 33 U.S.C. § 1365(d) seeking an award of attorney fees and litigation costs (including but not limited to expert witnesses' fees and costs). BNSF reserves the right to contest such a petition.

VII. FORCE MAJEURE AND EXCUSABLE DELAYS

29. BNSF shall perform all requirements under this Consent Decree in the manner and within the time limits established herein, unless performance is delayed or prevented by Force Majeure or Excusable Delay, which are defined for purposes of this Consent Decree as events or circumstances arising from causes not reasonably foreseeable and beyond the control of BNSF, or any entity controlled by BNSF or BNSF's contractors, which delay or prevent performance of any obligation under this Consent Decree despite due diligence and best efforts to fulfill the obligation. Events and circumstances beyond the control of BNSF may include, without limitation, earthquake, flood, hurricane, severe weather or other acts of God, war, riot, fire, injunction, labor stoppage, freight embargo, material shortages, and compliance with any law,

rule, or decree of any governmental body, either now existing or hereafter created, that conflicts with the requirements or obligations of this Consent Decree. Such events and circumstances do not include normal inclement weather, financial inability to complete the work, increased cost of performance, changes in BNSF's business or economic circumstances, or the failure to obtain federal, state, or local permits, authorizations and approvals, unless BNSF has made timely and complete application for such permits, authorizations, and approvals.

30. BNSF shall notify the Plaintiffs in writing within ten (10) business days after becoming aware of an event or circumstance that BNSF believes constitutes Force Majeure or Excusable Delay that may prevent or delay performance of an obligation under this Consent Decree. BNSF's notification shall describe in detail the anticipated length of the delay, the precise cause or causes of the delay, the measures taken and to be taken by BNSF to prevent or minimize the delay, and a timetable by which those measures will be implemented. BNSF shall adopt all reasonable measures to avoid or minimize any such delay. BNSF shall include in the notification a proposed extension of the deadline associated with any obligation under this Consent Decree whose performance may be prevented or delayed by unforeseeable events or circumstances beyond BNSF's reasonable control.

31. Unless BNSF's notice contains no reasonable basis to conclude that the circumstance, event, or anticipated event identified in the notice has caused or will cause a delay that constitutes a Force Majeure or Excusable Delay, the time for performance shall be extended by an appropriate period substantially equal to the necessary delay.

VIII. DISPUTE RESOLUTION

32. The Dispute Resolution procedures of this Section shall be the exclusive mechanism for the parties to raise and resolve disputes arising under or with respect to this Consent Decree (Covered Dispute).

33. A Covered Dispute shall be considered to have arisen when one Party sends the other Part(ies) a written Notice of Dispute.

34. Any Covered Dispute shall, in the first instance, be the subject of informal negotiations between the Parties in an attempt to resolve the dispute in good faith and in an expeditious manner. The Parties shall have thirty (30) days following receipt of a Notice of Dispute to reach agreement.

35. If the Parties cannot reach agreement on the dispute during the 30-day period provided under Paragraph 33, Plaintiffs and BNSF shall jointly file a motion with the Court requesting resolution of the Covered Dispute. Plaintiffs and BNSF shall append to that motion written statements not to exceed five (5) single-spaced pages (excluding attachments or exhibits) setting forth their respective proposed resolutions of the dispute.

36. The Parties shall comply with any written agreement reached as a result of informal negotiations conducted during the 30-day period provided for by Paragraph 33, including any extension of time to comply with a schedule or deadline required by this Consent Decree, so long as the agreement does not constitute a material change to any terms of this Consent Decree. Section X of this Consent Decree shall govern the process for any proposed material changes to the terms of this Consent Decree.

IX. NOTICES

37. Unless otherwise specified herein, any notification, submission, statement of position, or communication required by this Consent Decree shall be made electronically, unless otherwise requested, and addressed as follows:

As to Plaintiffs:	Charles M. Tebbutt, charlie@tebbuttlaw.com Daniel C. Snyder, dan@tebbuttlaw,com David Pettit, dpettit@nrdc.org Jessica Yarnall Loarie, jessica.yarnall@sierraclub.org
As to BNSF:	Timothy M. Sullivan, tsullivan@bdlaw.com Dava Kaitala, Dava.Kaitala@BNSF.com Brooke Gaede, Brooke.Gaede@BNSF.com

//

38. Any Party may, by written notice to all other Parties, change its designated notice recipient or notice address provided above.

39. Notices submitted pursuant to this Section shall be deemed submitted upon electronic transmission, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

X. MODIFICATION

40. This Consent Decree contains the entire agreement of the Parties and shall not be modified by any prior oral or written agreement, representation, or understanding. Any non-material modification of this Consent Decree after entry may be made without approval of the Court but must be in writing and approved by the Parties.

41. Any material modification to any term of this Consent Decree shall be effective only upon approval by the Court.

42. A Party shall not petition the Court for modification without having first made a good faith effort to reach agreement with the other Part(ies) on such modification. Notwithstanding the above, any Party may, after having made such effort, petition the Court for a modification of this Consent Decree and the Court shall rule on any such petition pursuant to law in effect at such time. Any ruling by the Court on a petition for modification may be appealed by a Party in accordance with law.

XI. TERMINATION

43. Upon completion of all of the work required by this Consent Decree, BNSF shall notify Plaintiffs in writing that it has fully satisfied all Consent Decree requirements. This notification shall indicate the case name and civil action number.

44. Should Plaintiffs disagree with BNSF's notification under Paragraph 43, Plaintiffs may invoke Dispute Resolution pursuant to Section VIII within ten (10) days of receipt of the

certification.

45. Following the notification that BNSF has completed all work required under the Consent Decree, either Party, or the Parties jointly, may move this Court to terminate this Consent Decree.

IT IS SO ORDERED.

DATED this 2nd day of May 2017.



John C. Coughenour
UNITED STATES DISTRICT JUDGE

APPENDIX A
Removal Sites

Description	Segment of BNSF Right Of Way Start	End
Rail Bridge at Drano Lake and Drano Lake Parking Area	45.710015 N, 121.639022 W	45°42'41.21"N 121°38'58.01"W
Confluence of White Salmon and Columbia Rivers	45°43'42.30"N 121°31'15.54"W	45.729216 N 121.524720 W
Confluence of Rock Creek and Columbia River	45°41'23.24"N 121°53'15.21"W	45°41'20.77"N 121°53'19.90"W
Horsethief Lake Site – Area in vicinity of public access to boat ramp and along the top of the causeway	45.646089 N 121.096466 W	45.639152 N 121.104766 W
Causeway near Murdock	45.658225 N 121.198597 W	45.658771 N 121.198875 W

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

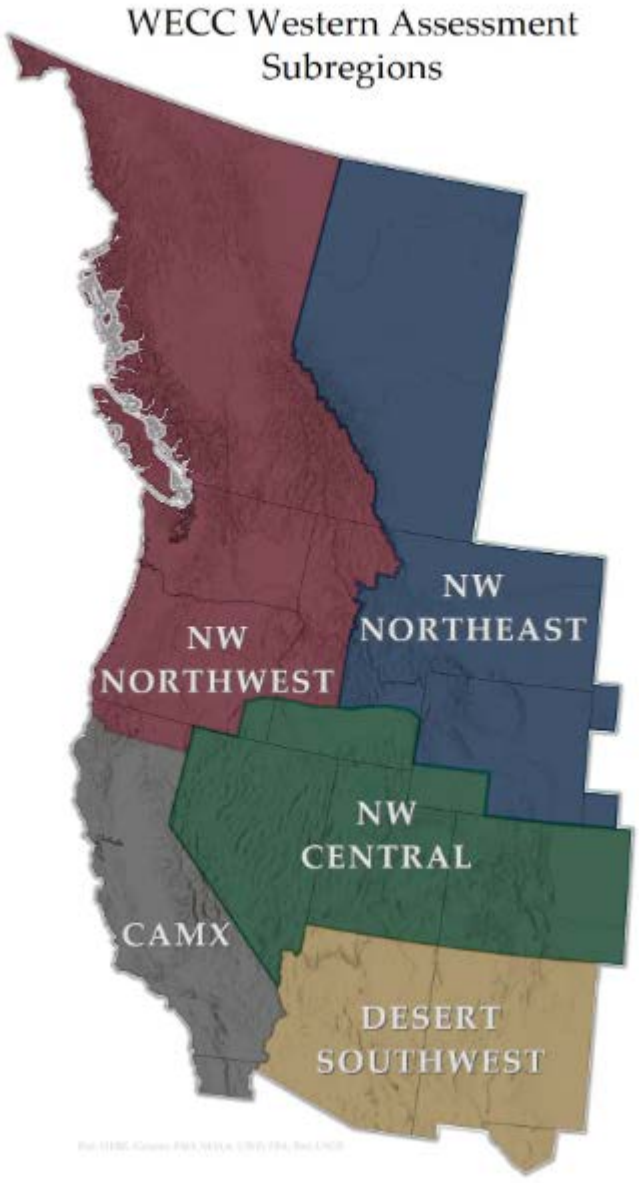
Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-137:
WECC 2024 Western Assessment of Resource Adequacy


WESTERN ASSESSMENT
OF RESOURCE ADEQUACY
2024

The pace of change is increasing the risks to reliability across North America. The supply of electricity is not growing fast enough to keep up with demand growth. What was once a simple problem of supply and demand has become complicated by rapid change and increasing variability. Unless we prioritize reliability as the resource mix evolves and becomes more variable, we are at risk for serious and more frequent disruptions. The West must move quickly and more decisively to ensure resource adequacy over the next decade.

WECC's annual Western Assessment of Resource Adequacy (Western Assessment) examines resource-adequacy-related risks concerning the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC looks at the risks throughout the interconnection and five subregions. This work is meant to help stakeholders target specific areas and topics for deeper evaluation and mitigation.



The forecast rate of demand growth over the next decade is double what was forecast just two years ago.

Current resource plans forecast staggering demand growth over the next decade. For the Western Interconnection, annual demand is forecast to grow 20.4%, from 942 TWh in 2025, to 1,134 TWh in 2034. That growth rate is more than double the 9.6% growth forecast in resource plans filed in 2022, and over four times the historical growth rate of 4.5% between 2013 and 2022.

New large loads create reliability challenges that must be addressed immediately.

A major driver for the increase in demand over the next 10 years is the expansion of large loads like data centers, manufacturing facilities, and cryptocurrency mining operations. These loads consume immense amounts of energy, can be constructed quickly, have different consumption patterns, and require changes or additions to infrastructure. In some cases, large loads require a steady supply of power at all times, while in other cases, their demand can fluctuate, creating a need for large ramping capability. There can be challenges with the way large loads behave during grid disturbances, including their ride-through capability. According to current plans, the effects of large-load growth are greatest in the next three to five years; however, more large loads will likely be added to future forecasts.

To meet growing demand, entities plan to build unprecedented amounts of new resources over the next decade. Never has generation been built in the West at the rate called for in current resource plans. These plans could be unattainable given past struggles to build planned resources on time.

Current resource plans include 172 GW of new generation resources to be built in the next decade. This is more than double the generation capacity added in the last 10 years and will require an exceptional effort to carry out. Between 2014 and 2023, entities added 74 GW of new generation. Demand growth and resource retirements are driving up the number of new resources needed in the next 10 years.

If demand grows as expected and industry experiences delays and cancellations in building new resources over the next decade, the West will face potentially severe resource adequacy challenges.

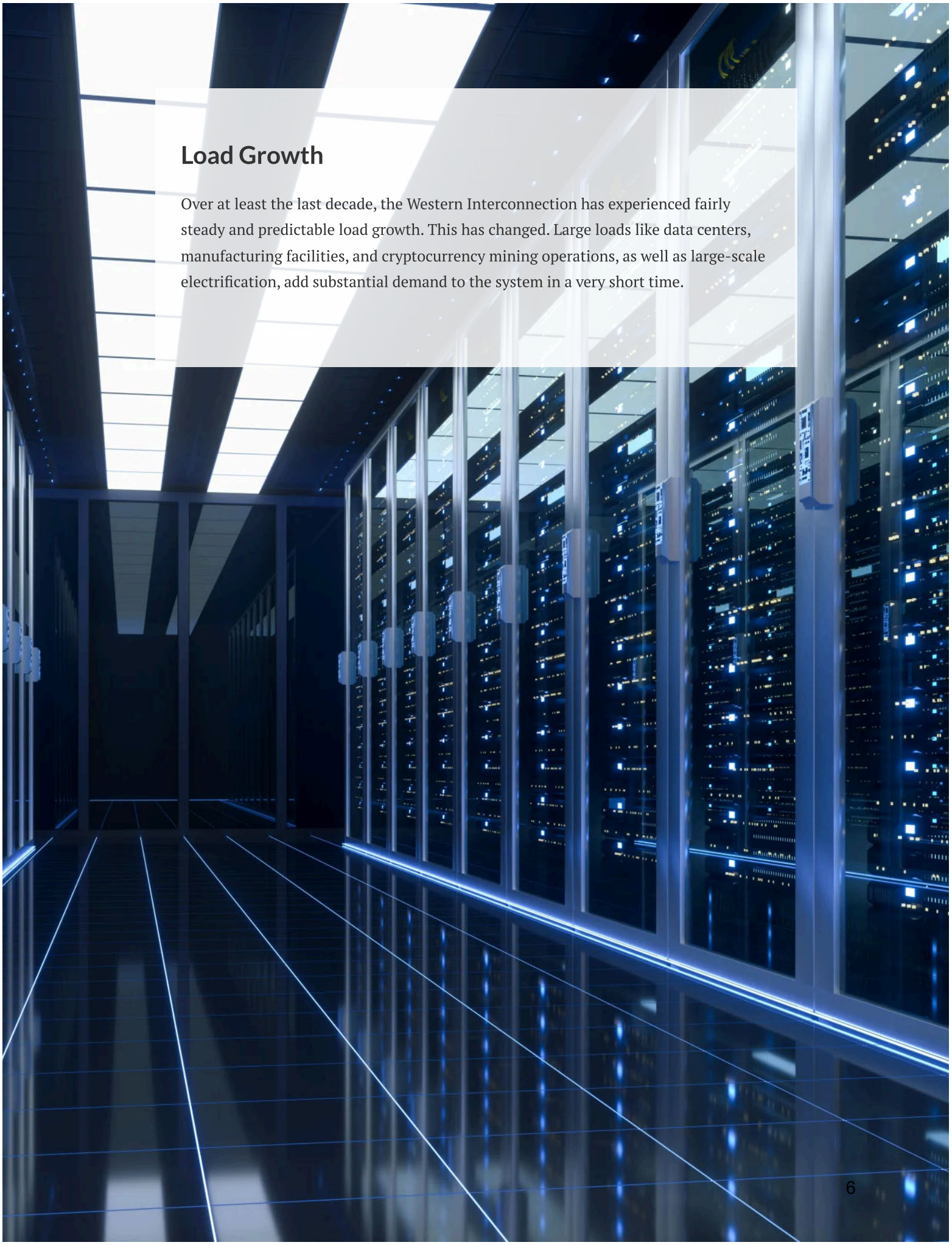
Over the last six years, only 76% of planned resource additions came online in the year scheduled, and in 2023, that number was 53%. Resource margins are shrinking, leaving less buffer for cancelled and delayed projects. If the resource build-out over the next 10 years mimics the last five years, by 2034, the West will have hundreds of hours each year when demand is at risk.

Variability will continue to increase, exacerbating the risk of having inadequate dispatchable energy.

Over 85% of the 172 GW of planned resource additions in the next decade are variable resources (wind and solar), battery storage, or a hybrid. The addition of so many energy-limited resources, along with decreases in baseload resources and changes in load patterns, is creating more variability in the system. This increases uncertainty as to when and how much energy is needed and available. As uncertainty increases, risk increases.

Is the current resource planning structure adequate?

Entity resource plans seem overly optimistic. While planning entities provide specific information about the resources they plan to add in the next one to five years, in many cases, they provide generic, non-specific "placeholder" resources in long-term planning five to ten years out. Traditional resource planning and review practices do not have a mechanism to ensure that resources will actually be built.



Load Growth

Over at least the last decade, the Western Interconnection has experienced fairly steady and predictable load growth. This has changed. Large loads like data centers, manufacturing facilities, and cryptocurrency mining operations, as well as large-scale electrification, add substantial demand to the system in a very short time.

Load Changes

Annual Demand

Demand for electricity across the Western Interconnection is expected to grow 20.4% over the next 10 years. That is more than double the 9.6% growth projected in resource plans filed in 2022. Much of this increase is attributed to plans for large load facilities across many areas in the West. The greatest area of load growth is the Desert Southwest (DSW), which is forecasting almost 35% load growth over the next decade.

The issue is not confined to the 10-year future. Large-load growth affects every year over the next decade, with greater effect in the next few years. For example, in 2023, the load projections for the NW-Central subregion showed a change from 128 TWh in 2025 to 139 TWh in 2034. This year's projections show an alarming increase in both the near and long-term: from 167 TWh in 2025 to 190 TWh in 2034. Data centers, manufacturing facilities, and to a lesser extent electrification, are driving this increase.

Peak Demand

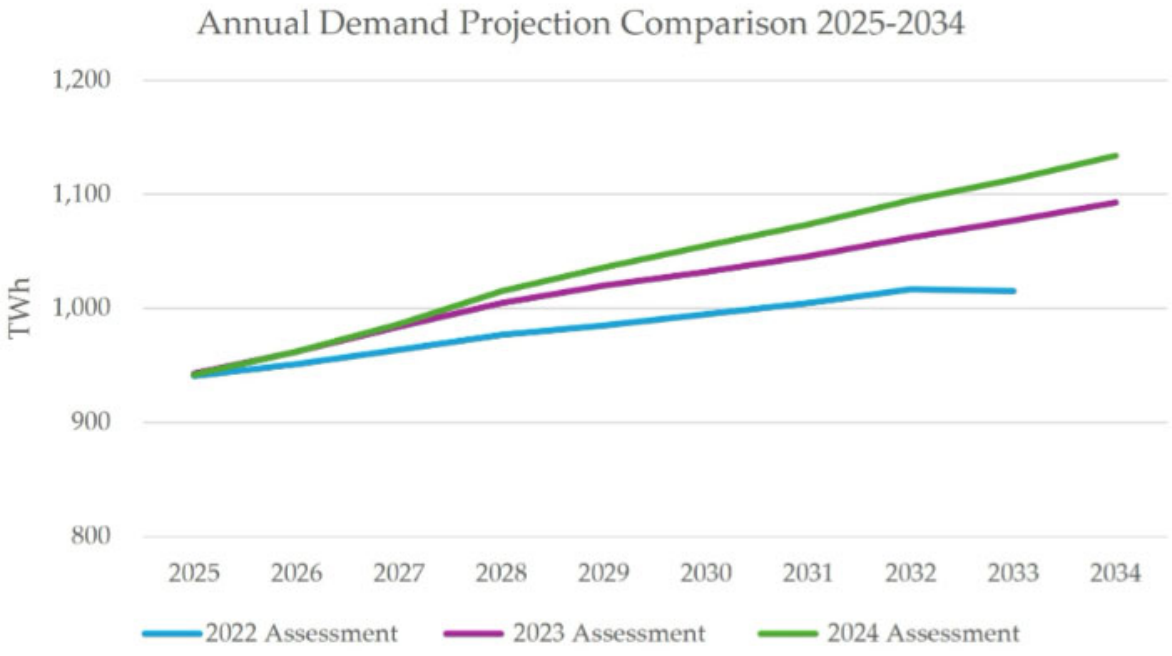
Peak demand in the Western Interconnection occurs in the summer. Based on plans submitted by the BAs, the expected peak demand for the Western Interconnection will grow from 164 GW in 2025 to 193 GW in 2034, an increase of 17.2%. This represents a slight increase from 2023 resource plans.

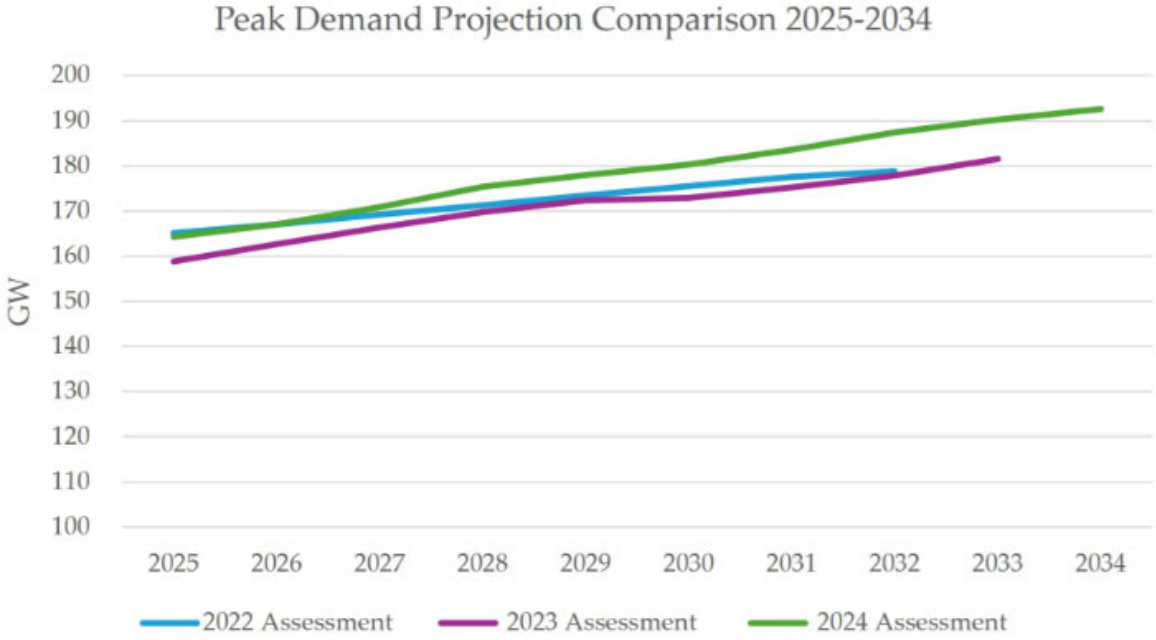
According to 2024 resource plans, the projected peak is slightly lower for NW-Central than it was in 2023 plans, while it is slightly higher for the DSW subregion. For the California-Mexico (CAMX) subregion, the peak reflected in 2024 plans is also slightly lower each year until 2034, when the projected peak demand is identical (66 GW) to the projections made in 2023. The projections for NW-Northeast have not changed much between 2023 and 2024 resource plans, while the 2024 projections are slightly lower for the NW-Northwest subregion.

In addition, although the peak demand in the Western Interconnection overall occurs in the summer, many entities see their peak demand in the winter. As the climate changes, some of these entities are becoming dual-peaking. This introduces challenges to resource planning for entities that have historically seen one predominant peak.

See the appendix for more information about the drivers of load growth.




Annual Demand Projection Comparison 2025-2034
TWh
1,200
1,100
1,000
900
800
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2022 Assessment
2023 Assessment
2024 Assessment

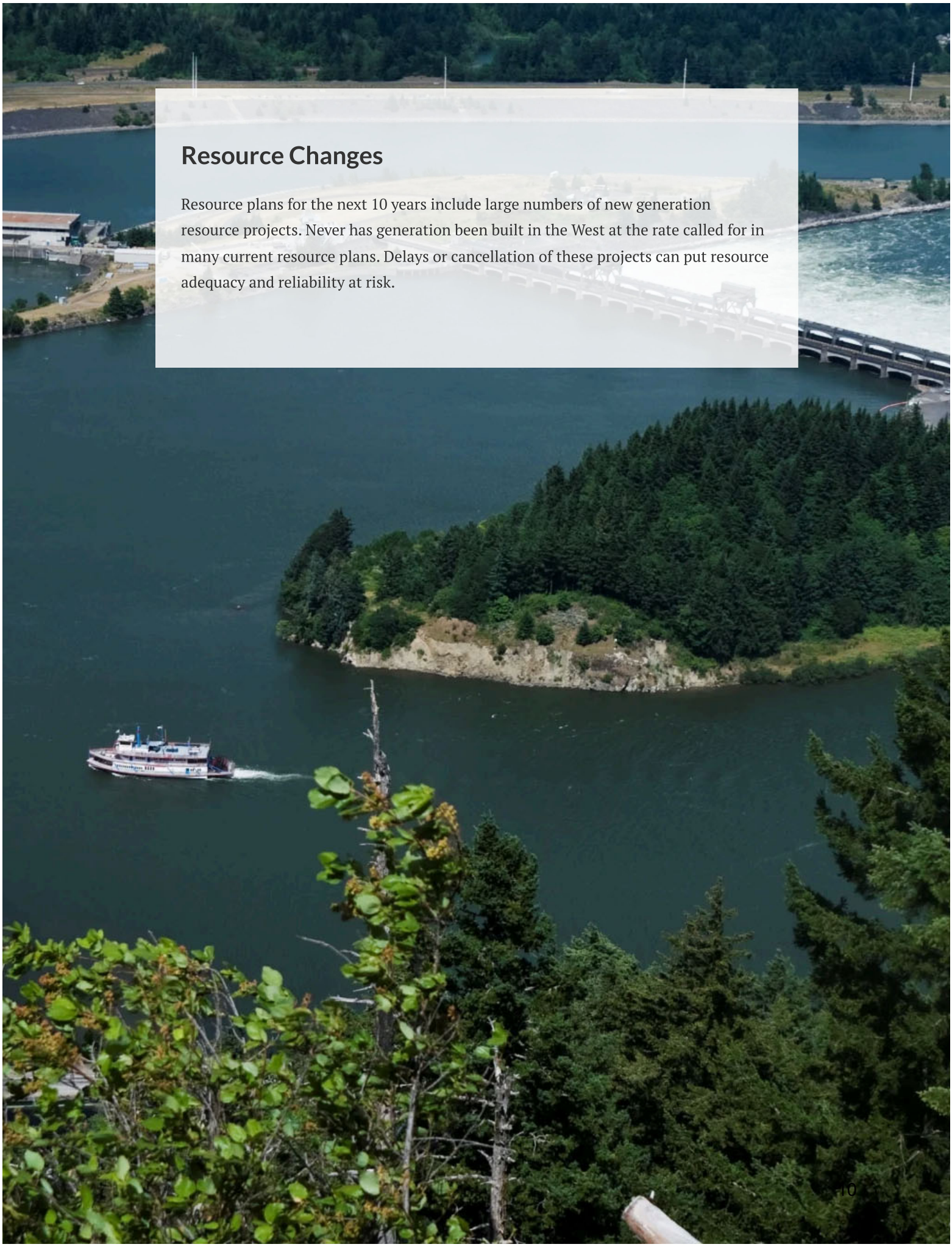

Peak Demand Projection Comparison 2025-2034
GW
200
190
180
170
160
150
140
130
120
110
100
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2022 Assessment
2023 Assessment
2024 Assessment



Impact of Large Loads

Large loads like data centers, manufacturing facilities, and cryptocurrency mining operations add a large amount of concentrated load to the system. In some cases, new large loads inundate a service area, overwhelming existing infrastructure. Some new large-load consumption patterns are different than traditional load patterns, requiring around-the-clock energy. Others have a significant amount of variability.

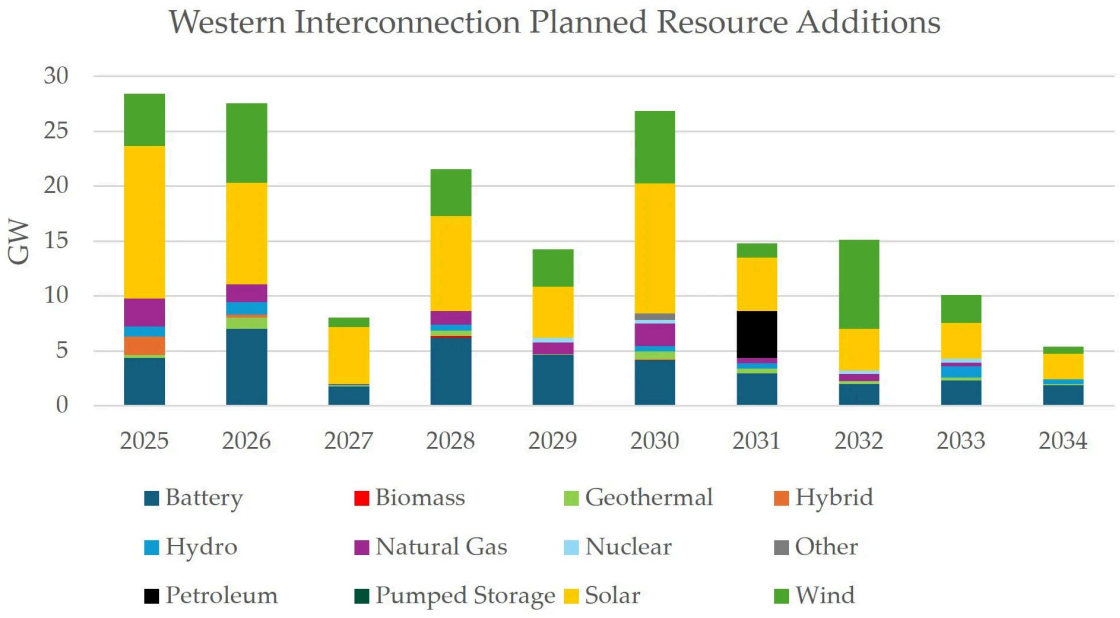
Integrating large loads often requires changes or additions to power system infrastructure. Large-load facilities can be built relatively quickly, as fast as 18 months, while building new generation resources and transmission infrastructure can take years. In addition, the question of cost allocation can complicate the construction of new infrastructure.



Resource Changes

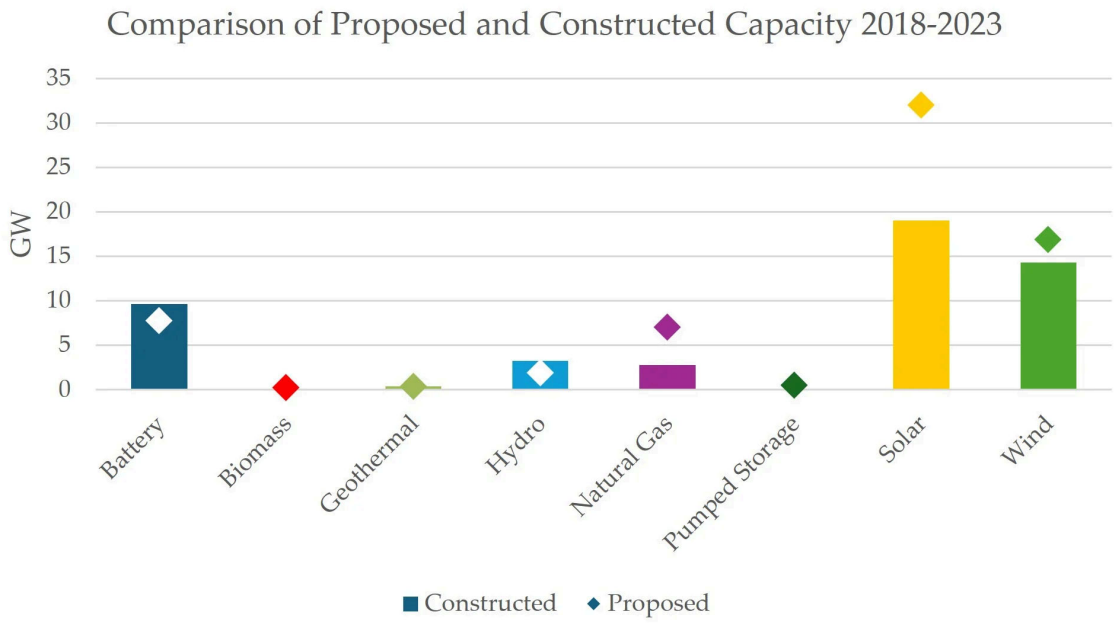
Resource plans for the next 10 years include large numbers of new generation resource projects. Never has generation been built in the West at the rate called for in many current resource plans. Delays or cancellation of these projects can put resource adequacy and reliability at risk.

Planned Additions



Planned Resource Additions

Over the next decade, entities in the Western Interconnection plan to add more than 172 GW of new generation capacity—almost 145 GW in battery storage, solar, and wind, according to resource plans filed in 2024. i That is up from 121 GW of resources in 2023 10-year plans i and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.



Historical Resource Additions

Between 2018 and 2023, approximately 76% of the proposed resource additions came online in the year scheduled. In 2023, only 53% of the new generation resources i scheduled to come online that year actually came online; the rest were delayed or cancelled.

Go here for a breakdown of the planned resource additions by subregion over the next decade.

according to resource plans filed in 2024. That is up from 121 GW of resources in 2023 10-year plans and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.

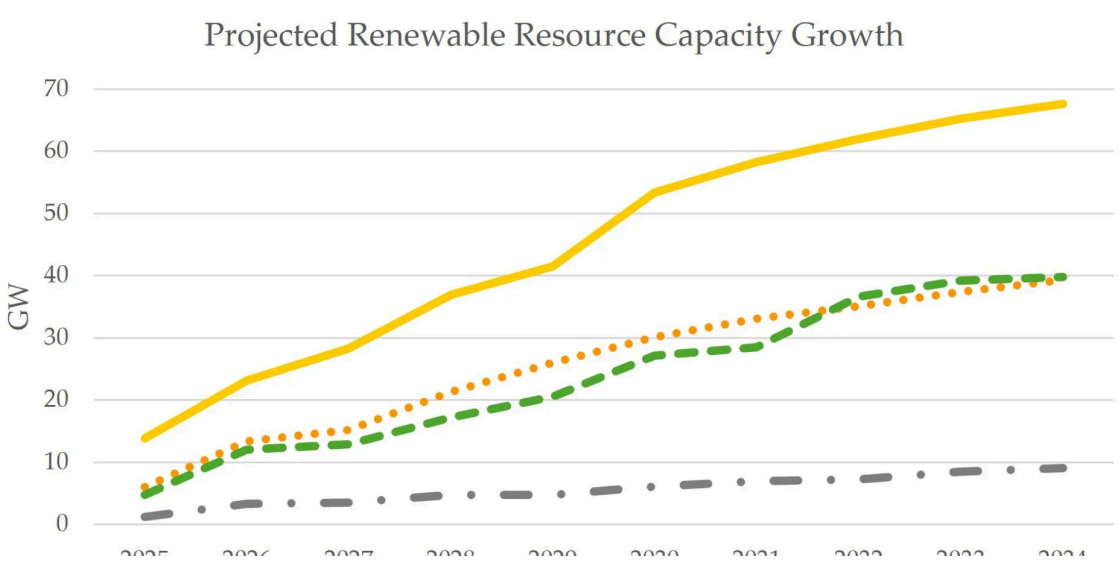
The Western Assessment relies on data submitted by the Balancing Authorities (BA) that describes projected hourly demand and resource projections over the next 10 years.

according to resource plans filed in 2024. That is up from 121 GW of resources in 2023 10-year plans and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.

Historical Resource Additions

Other refers to generation types such as wood, oil, and non-gas biomass.

Between 2018 and 2023, approximately 76% of the proposed resource additions came online in the year scheduled. In 2023, only 53% of the new generation resources scheduled to come online that year actually came online; the rest were delayed or cancelled.

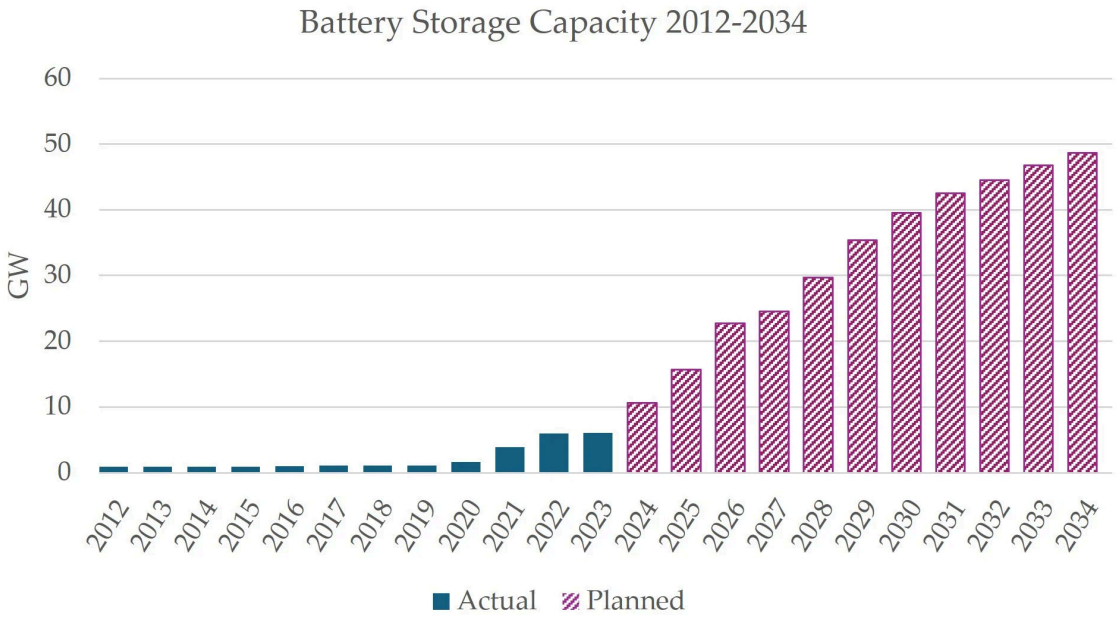


Solar

Entities plan to add nearly 68 GW of solar capacity over the next decade, more than any other resource. This will almost triple the amount of solar capacity that was in operation in 2023 (35 GW).

Wind

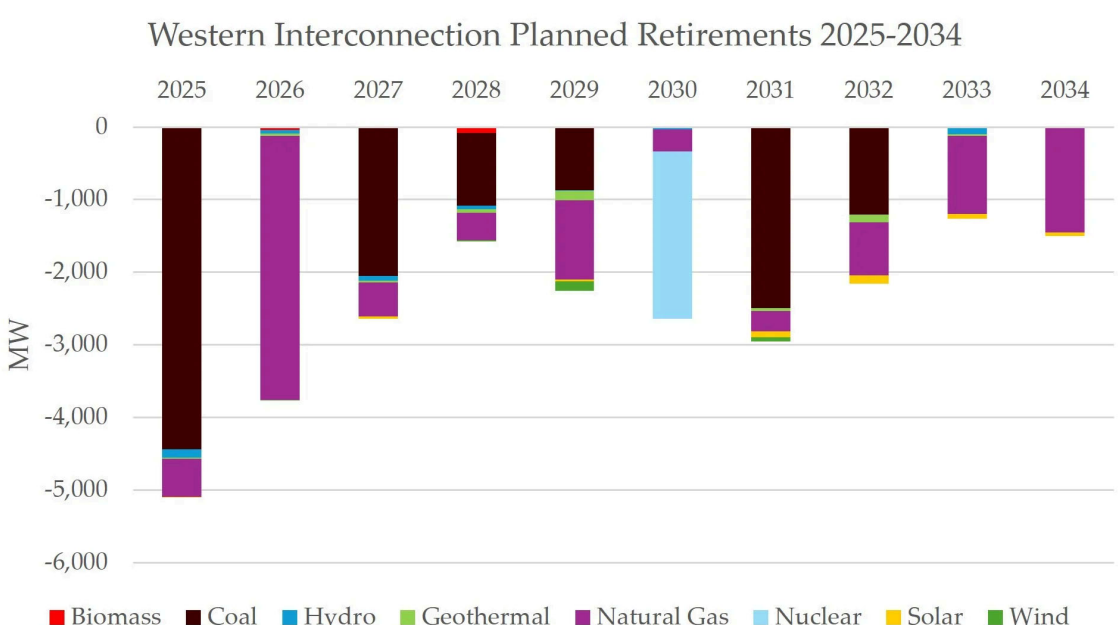
Wind capacity is projected to grow by nearly 40 GW from now until 2034. This increase will more than double the 37 GW in operation in 2023.



Battery Storage

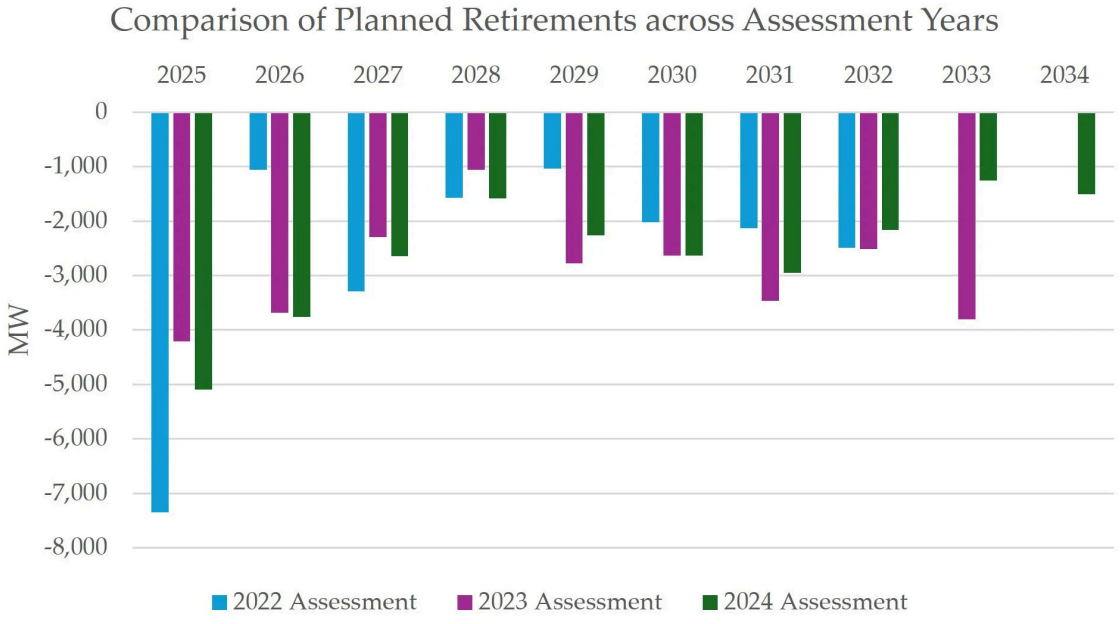
According to 2024 resource plans, battery storage will grow by more than 37 GW by 2034. In 2022, resource plans projected a total of 23 GW of storage by 2032, and that was 14 times more than what was operational in 2021 (1.6 GW). As of 2023, there was more than 10 GW of energy storage (battery and other forms of storage) installed in the Western Interconnection, primarily batteries but also pumped hydro. One major driver of new storage is the extension of the investment tax credit (ITC) for storage-solar projects and creation of a 30% ITC for standalone storage.

Retirements



Planned Retirements

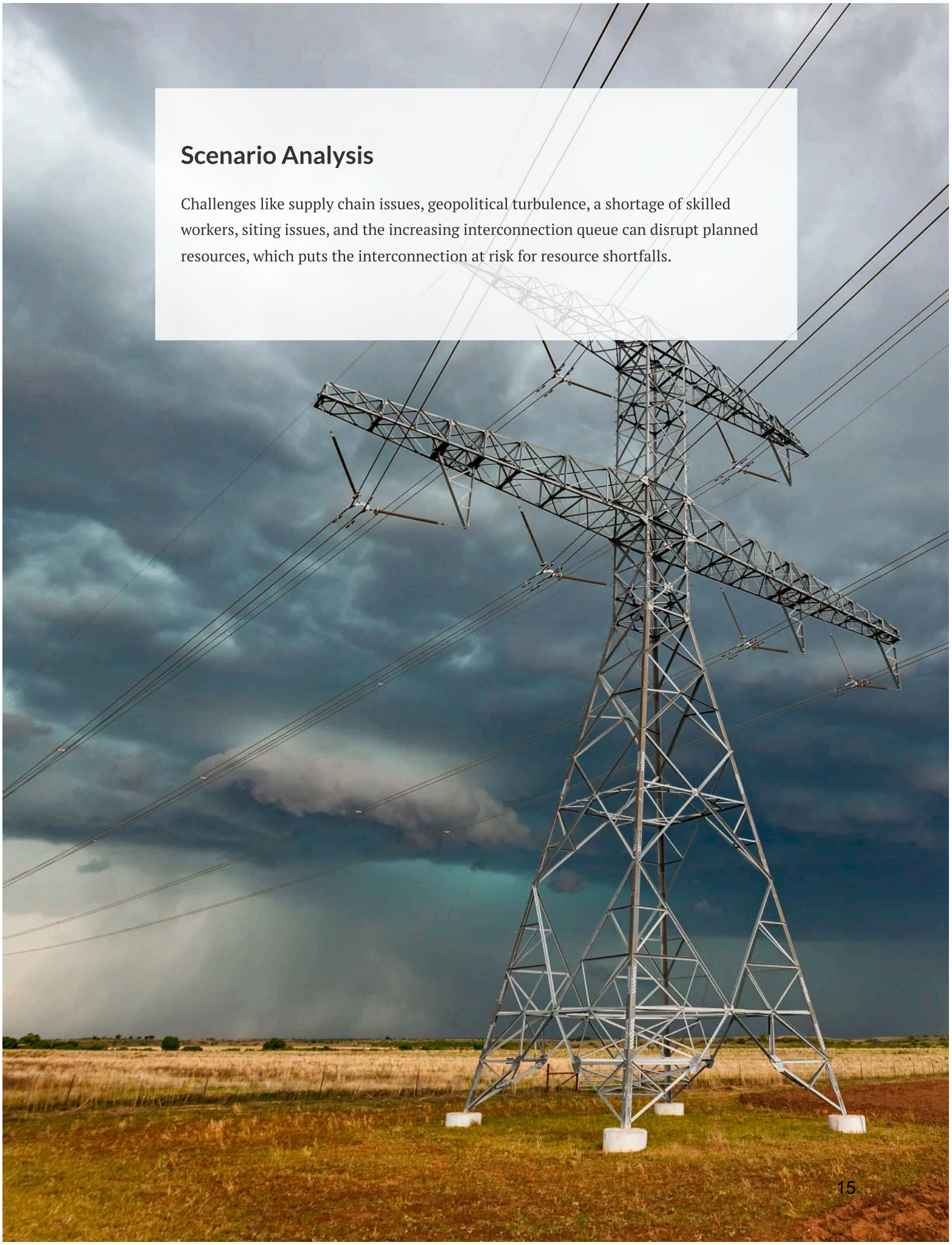
Entities plan to retire 25.85 GW of generation over the next 10 years. This is down slightly from resource plans filed in 2023, in which entities planned to retire 27 GW over the next decade, but is up considerably over the last 10 years. Retirement dates over the coming decade varied slightly compared to resource plans filed a year ago, but did not vary as much compared to the retirement delays we saw in 2023 resource plans. In 2025, for example, current resource plans call for 5.1 GW to retire, up from 4.2 GW in 2023 resource plans (but still down considerably from 2022 plans, when 7.4 GW were slated for retirement in 2025). Current plans also show a significant change in retirements in 2033. A year ago, 3.8 GW was set for retirement in 2033; in 2024, that dropped to 1.3 GW.



Changes in Planned Retirements

Most of these planned retirements (more than 24 GW) are baseload generation, such as coal, natural gas, and nuclear. In 2025, more than 4.4 GW of coal is set for retirement, and more than 3.6 GW of gas is slated for retirement in 2026.

In December 2023, California regulators voted to allow Diablo Canyon nuclear plant to remain open an additional five years—until 2030; it had been set to close in 2025. Diablo Canyon's two reactors have a combined generating capacity of more than 2.2 GW and accounted for 7% of California's in-state electricity generation in 2023.



Scenario Analysis

Challenges like supply chain issues, geopolitical turbulence, a shortage of skilled workers, siting issues, and the increasing interconnection queue can disrupt planned resources, which puts the interconnection at risk for resource shortfalls.

Scenario Analysis

One way WECC measures resource adequacy risk is by analyzing the number of hours in a year when there is a risk for potential load loss (demand-at-risk hour). A demand-at-risk hour is one in which the risk for potential load loss exceeds a risk tolerance threshold. WECC uses the one-day-in-ten-years (ODITY) or 99.98% reliability threshold. If the probability of load shed for any given hour is greater than the ODITY threshold, it is counted as a demand-at-risk hour. Demand-at-risk hours are not a prediction that demand will be lost; they indicate times when load is at risk of being lost because under certain conditions the interconnection does not have enough energy to meet demand.

Historically, the number of new resources that were built according to plan and on time has varied. In 2023, only 53% of planned resources were successfully built and brought online as scheduled. In other years the success rate was better. Between 2018 and 2023, only 76% of planned resource additions came online as scheduled.

If the past is a model for building planned resources over the next 10 years, resource adequacy will be at risk. To examine this, WECC evaluated four resource build-out scenarios:

- All planned resources are built on time
- 95% of planned resources are built on time
- 85% of planned resources are built on time
- 55% of planned resources are built on time

All Additions Scenario

If all planned additions are completed and operational on time, there are 89 demand-at-risk hours over the next decade.

95% Scenario

In this scenario, there is demand at risk in every year except 2024 and 2026. In 2025, there are three hours of demand at risk, all in the NW-Northwest subregion. By 2034, that number increases to 91 demand-at-risk hours across the NW-Northwest and NW-Northeast subregions.

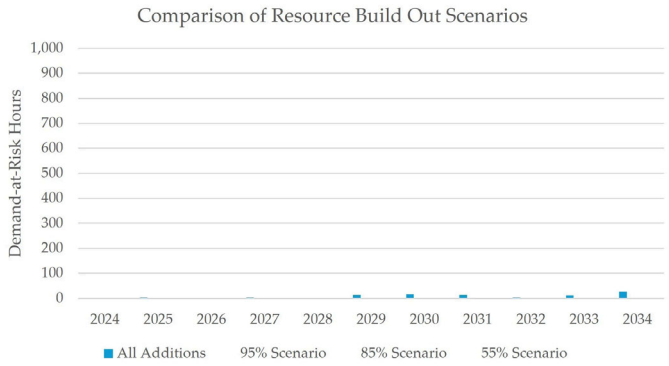
- NW-Northwest: Most of the demand at risk is in this subregion, including all three hours in 2025 and 82 hours in 2034.
- NW-Northeast: A total of 46 hours of demand is at risk over the next 10 years.

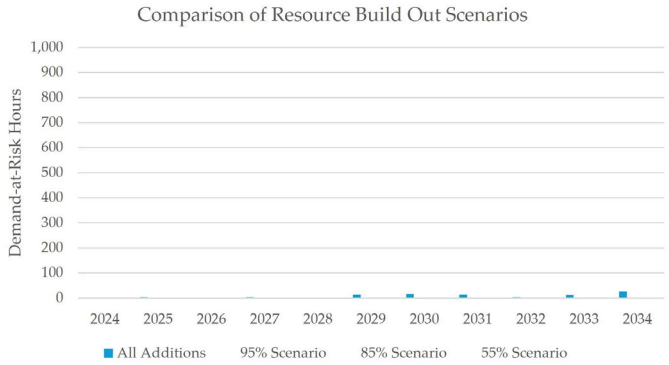
85% Scenario

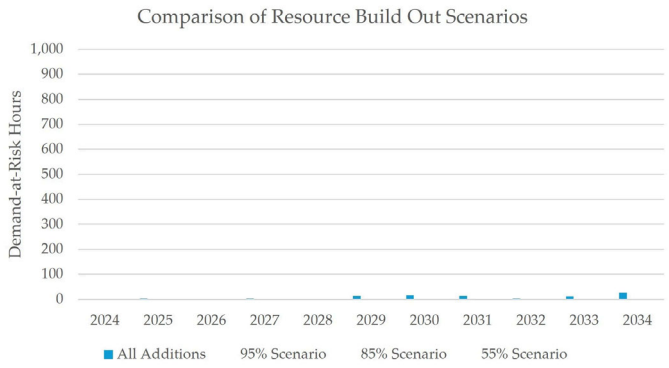
If only 85% of resources are built on time, demand at risk begins to increase significantly in 2029, when 36 hours are at risk. This increases nearly every year until 2034, when 129 hours of demand is at risk. The vast majority of the demand at risk is in the NW-Northwest subregion.

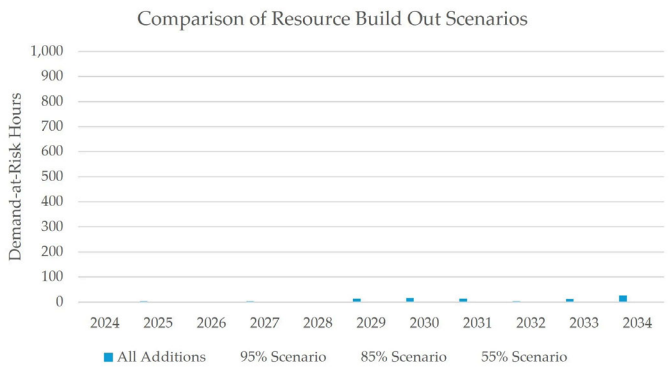
- NW-Northwest: There is minimal impact in the short-term—a total of 16 hours of demand at risk through 2028. That increases nearly every year through the end of the 10-year period, peaking at 87 demand-at-risk hours in 2034.
- NW-Central: Demand-at-risk hours appear in 2031, with a total of 16 hours, and increase to 41 hours in 2034.

55% Scenario





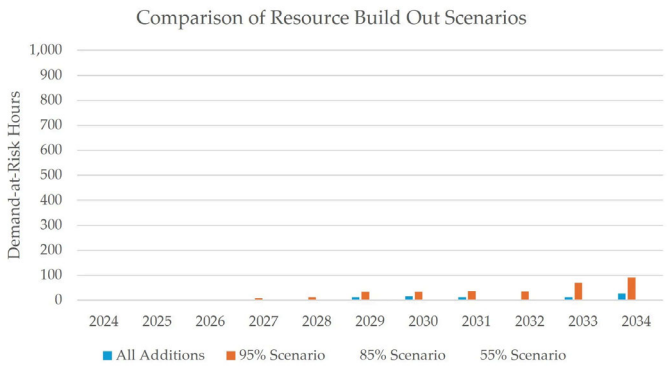


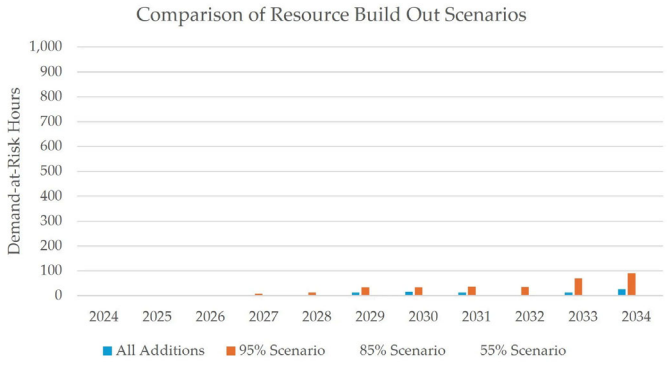


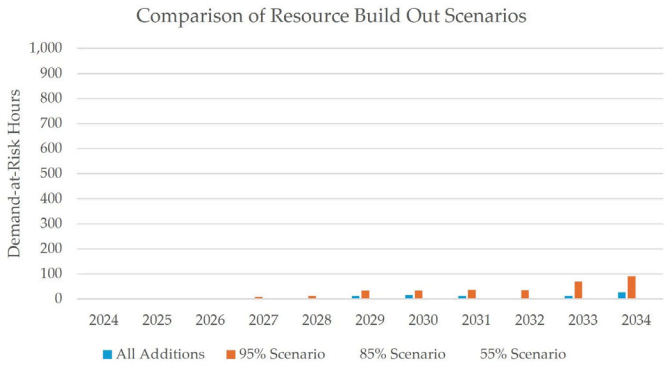
In this scenario, there are a total of eight demand-at-risk hours in 2025 growing to 952 hours by 2034.

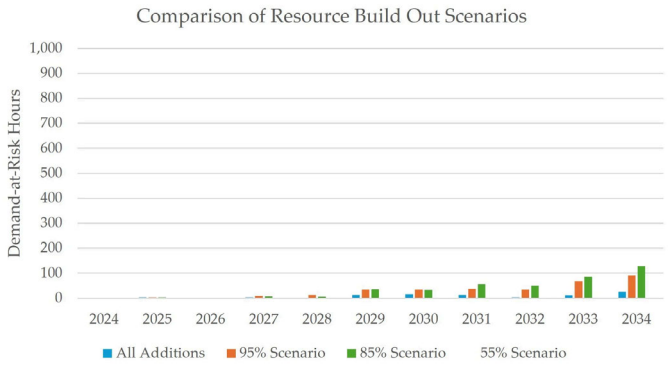
- CAMX: CAMX relies heavily on imports, resulting in no demand-at-risk hours in this scenario.
- DSW: Demand is at risk starting in 2028 (one hour) and increases to 69 hours in 2034.
- NW-Northwest: Demand is at risk every year over the 10-year period, starting with 8 hours in 2025 and climbing to 787 hours in 2034
- NW-Northeast: Demand is at risk every year starting in 2029 with two hours and increasing to 31 hours in 2034
- NW-Central: Demand is at risk after 2031, with a maximum of 65 hours in 2034

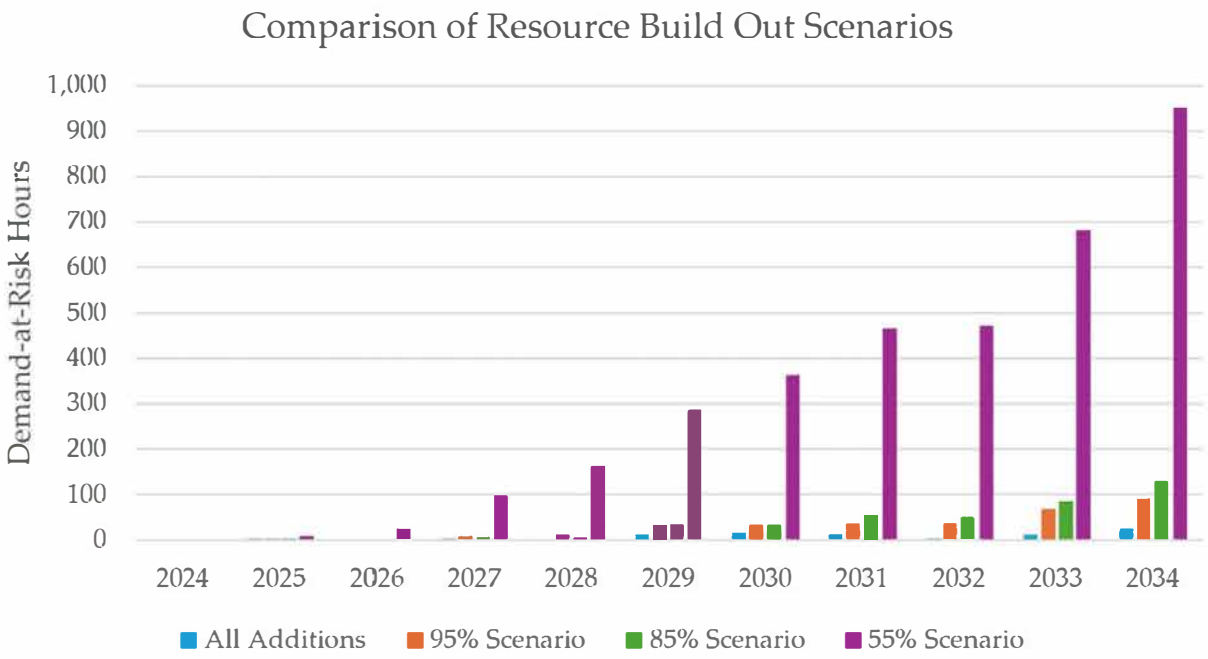
See the appendix for information on how demand at risk was calculated.










Comparison of Resource Build Out Scenarios
Demand-at-Risk Hours
1,000
900
800
700
600
500
400
300
200
100
0
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
All Additions
95% Scenario
85% Scenario
55% Scenario



Risks to Planned Resource Additions



Supply Chain Disruptions

Supply chain issues that surfaced during the pandemic in 2020 continue to affect the industry, particularly the construction of new projects and the interconnection of new generating resources. A recent survey found that supply chain issues remain a significant problem in 2024.



Interconnection Queue

The interconnection queue nationwide grew more than 30% in 2023 and has increased eightfold in the last decade. The planned additions over the next 10 years will exacerbate this issue, although FERC Order 2023 calls for reforms to reduce the backlog and address uncertainty in the interconnection process.



Siting Delays

There has been increasing resistance to building new energy facilities, particularly wind, solar, and battery projects. These projects have encountered opposition in at least 45 states, according to a recent report that found that local opposition to new energy facilities is widespread and growing.

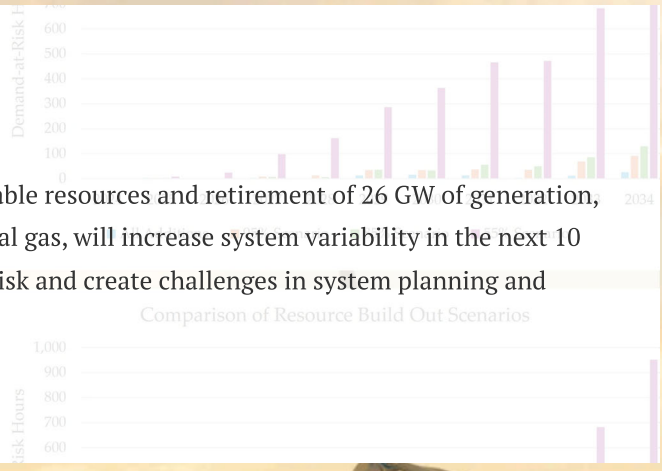


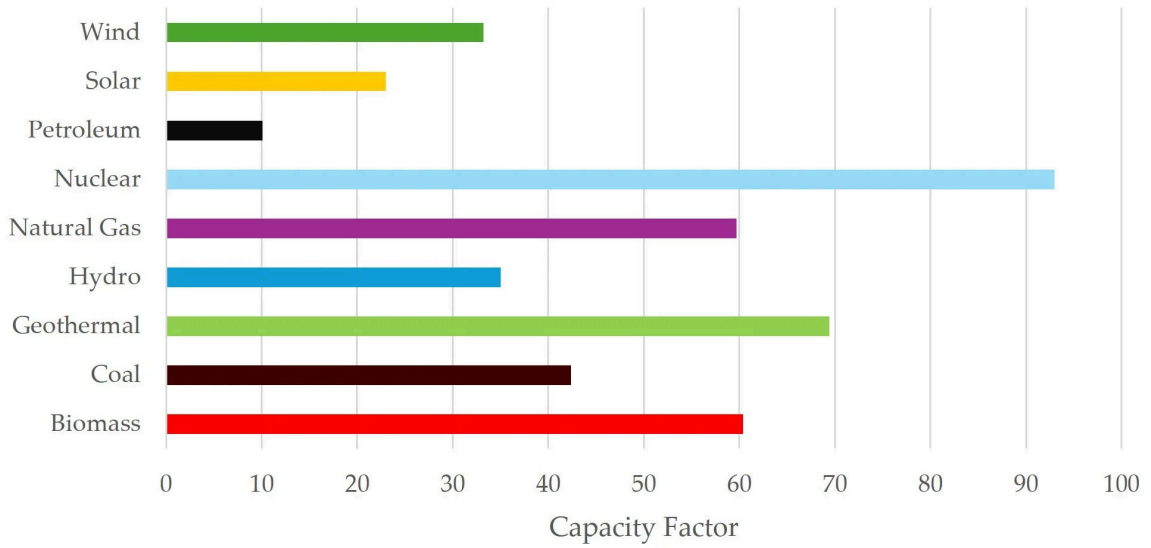
Increased Costs

Increased costs of materials for new wind and solar construction, transmission expansion, and replacement of plant equipment have caused project delays and maintenance deferrals. The rise in interest rates in recent years has also substantially increased the cost of capital for all energy projects.

Variability

The addition of 107 GW of variable resources and retirement of 26 GW of generation, most of which is coal and natural gas, will increase system variability in the next 10 years. These changes increase risk and create challenges in system planning and operation.





Replacing Generation Resources

Over the next decade, the addition of 107 GW of wind, solar, and battery hybrid generation must cover load increases and replace 26 GW of retired resources, of which almost 25 GW are coal, natural gas, and nuclear resources. The capacity factor of variable resources is lower than baseload resources like coal, natural gas, and nuclear. Replacing the 25 GW of retired baseload resources will require much more installed capacity of wind, solar, and storage resources.

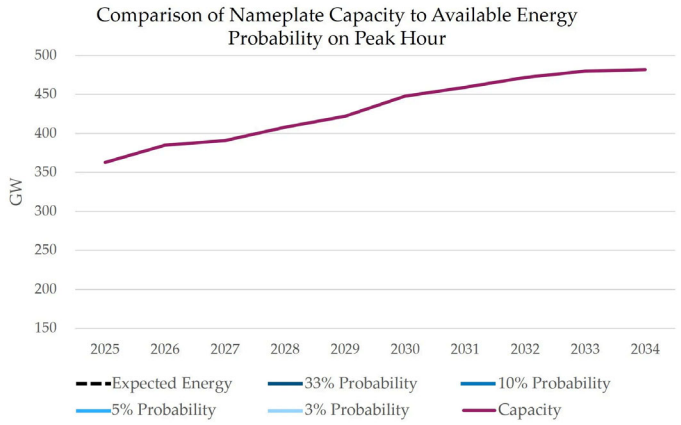
The capacity factor is the ratio of energy produced by a generating unit over a period of time to the amount of energy the unit could have produced at full power (or nameplate capacity). The chart shows average capacity factors by resource type across the U.S. (Source: EIA Electric Power Monthly)

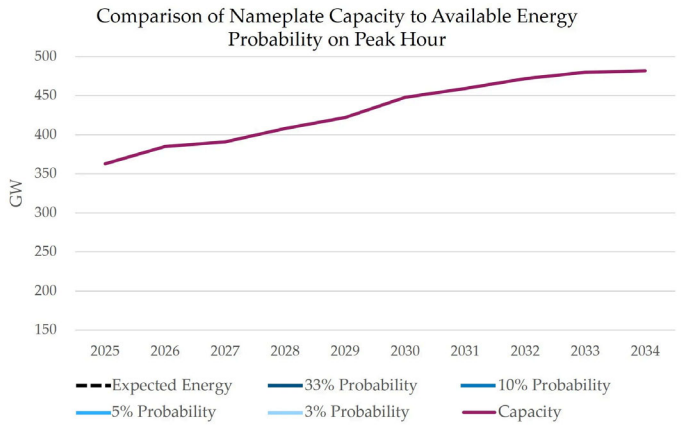


Traditionally, resource planning has been based on capacity and focused on ensuring there is enough capacity to meet peak demand. This has been based on the assumption that resources are available as expected (accounting for forced outages). However, with increasing variability, looking only at resource capacity is no longer enough. An examination of energy availability is crucial to ensuring the West has enough energy to meet demand at all hours of the year.

WECC receives nameplate capacity and historical generation information from Balancing Authorities. From this, WECC calculates the expected energy output of each resource and aggregates that number to get the expected energy for the entire resource fleet. The expected energy is lower than the nameplate capacity because resources do not produce at full capacity all the time. An increase in energy-limited resources widens the gap.

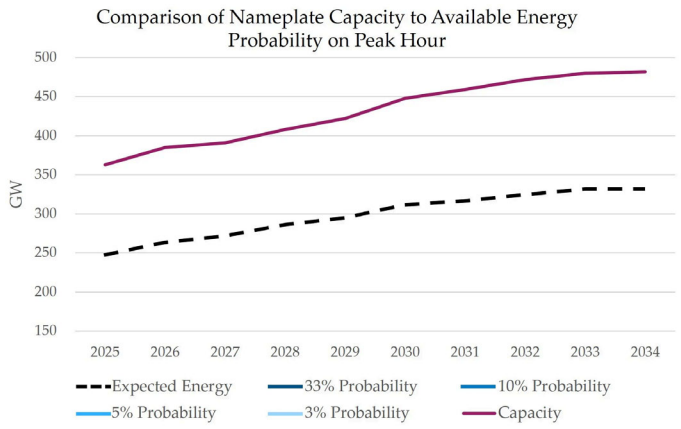
As the variability of the resource mix increases, so does the range of possible generation output at any given time. Depending on system and resource fleet conditions, more or less than the expected energy may be available. Instances when less energy is available can create risk, particularly when load is high. This can be the case during extreme weather events that cause simultaneous load increases and reductions in wind and solar output.

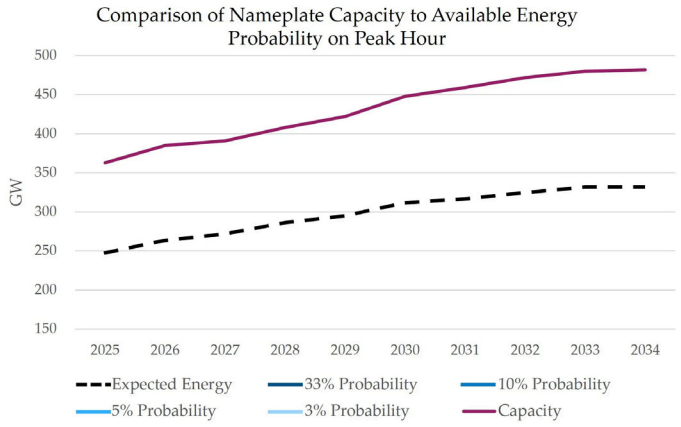


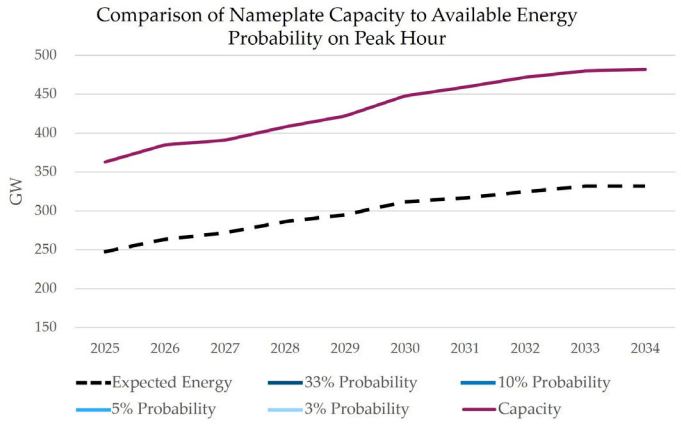


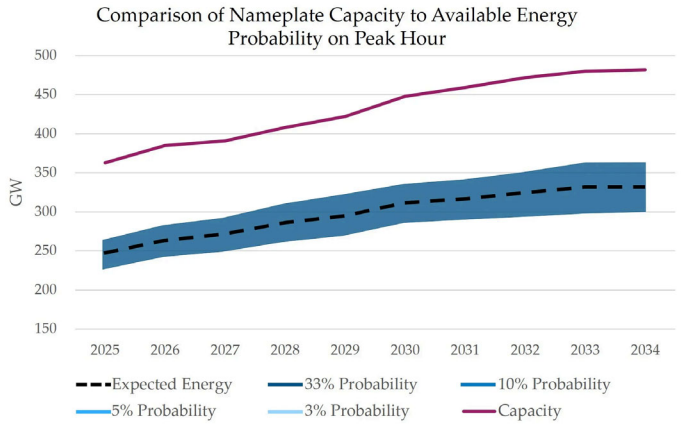
To address this, WECC calculates the probability distributions for each resource in the fleet. These distributions show the probability that a resource will generate at levels other than the expected level. The probabilities form a band of variability where the most likely output is in the middle and the least likely outputs are at the edge. The wider the band, the higher the variability on the system and the more possibilities planners and operators need to account for.

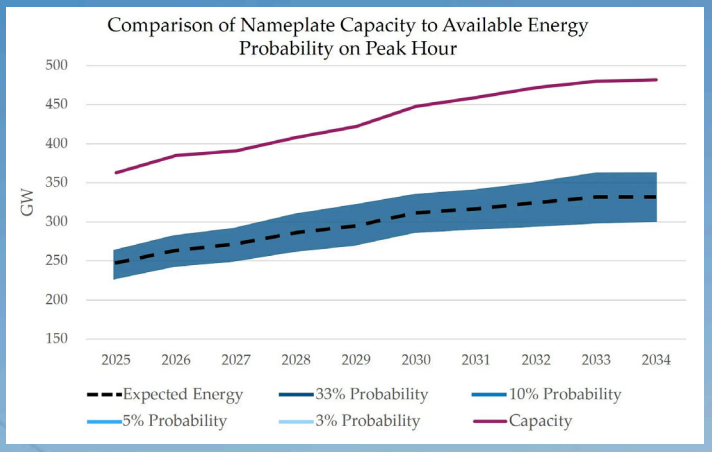
The size of the variability band increases over the next decade, indicating that while the West is building large amounts of new resources, the overall variability of the resource fleet is increasing.

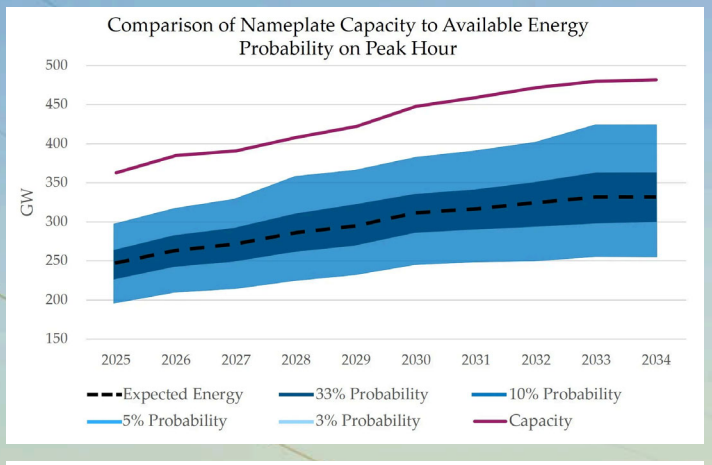


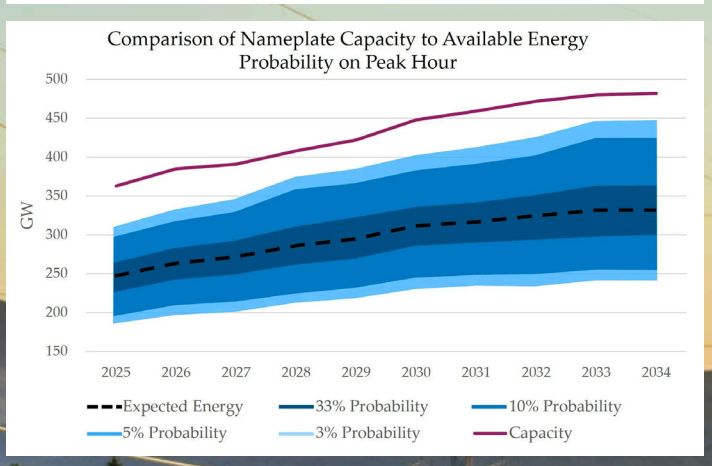


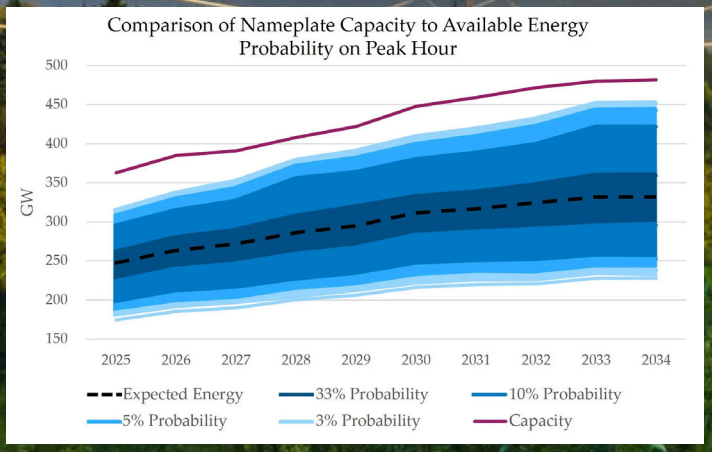












Resource Planning

Existing resource planning practices allow a lack of specificity about the resources entities need to meet demand, particularly in the long term. The resulting uncertainty about future resource additions puts the resource adequacy of the interconnection at risk.



Planning Resource Additions

Planning entities provide WECC with information about new resources they will need to meet demand over the next 10 years. In the near term, this information includes specific resource additions for the next one to five years. Typically, entities have a higher level of certainty about these resources because they are in some state of development. (Tier 1 or Tier 2 resources) Entities also include resources that are not yet under development (Tier 3 resources). When Tier 3 resources are included in near-term plans, they often reflect specific resources the entity can add relatively quickly (Tier 3 Specified). When they are included in later years of a resource plan, they are usually generic placeholder resources (Tier 3 Generic). In these cases, there is less certainty about whether the resource will be built. These resources often lack unit characteristics and may be grouped together instead of listed as individual plants or units.

In the past, when there was steady, predictable load growth and a generation surplus, entities could grossly estimate the resources needed 5 to 10 years in the future and hone those plans later. There was enough surplus generation in the interconnection to cover situations where new resources were built late, cancelled, undersized, or when demand increased unexpectedly. However, given the level of change in the West, the large amounts of new generation needed over the next decade, and obstacles to building it, delaying long-term resource decisions may put the resource adequacy of the interconnection at risk. This leaves the industry in a difficult position, because it needs more clarity about the future in a world that is becoming increasingly hard to predict. Resource plans that include large amounts of Tier 3 resources likely overestimate the ability to build generation.

Recently, there have been efforts to conduct longer-term planning on a 20-year horizon to meet needs identified by industry and the Federal Energy Regulatory Commission (FERC). In its Order 1920, FERC requires 20-year transmission planning to ensure the industry is preparing for the long-term future of the electric grid. While planning further out may allow the industry to see potential risks sooner, that work is only as good as the information on which it relies. Planning entities struggle to specify new resources in their 10-year resource plans; hypothesizing a resource mix in the 20-year future to study transmission may be incredibly challenging. To be successful, requirements for 20-year—and longer—planning horizons will spur advances in long-term resource planning.

Balancing Authorities provide WECC with information on planned resources classified into three tiers:
- Tier 1: resources that are under construction and expected to be complete and available for the year being studied
- Tier 2: resources that are under contract but have yet to begin construction. These resources may be operational by the year being studied.
- Tier 3 Generic: Generic placeholder resources that an entity has less certainty about.
- Tier 3 Specified: These Tier 3 resources may include capacity, type, and location information, but other unit characteristics and specific commission date are not known, and the project hasn't been started.

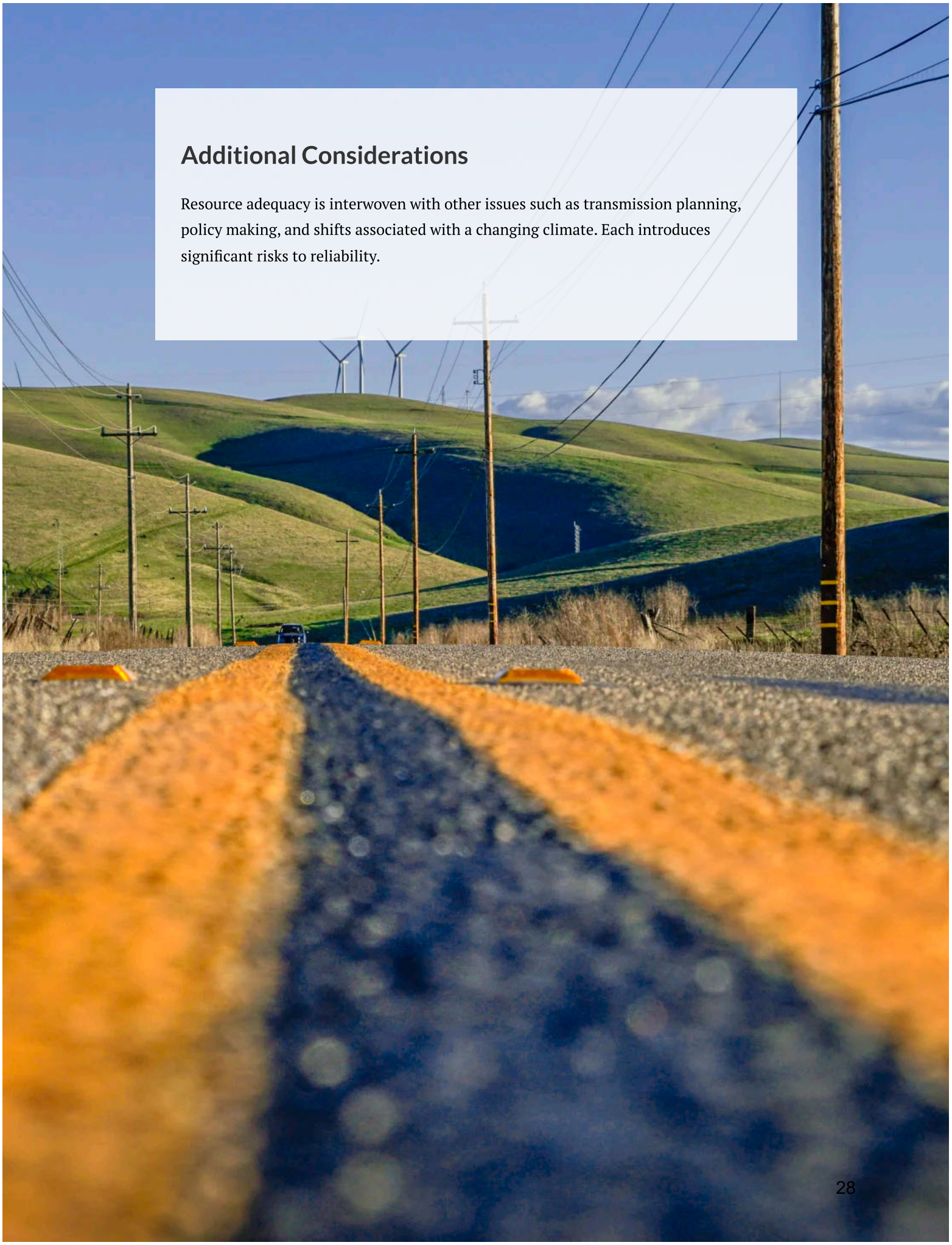
Resource Adequacy Programs

Resource adequacy programs can help manage resource adequacy by taking advantage of operating efficiencies and diversity across the entities in their footprint. The California ISO's reliability requirements program sets resource adequacy requirements for load serving entities in the ISO. The CAISO program has functioned for years and is integrated with its other functions.

The Western Resource Adequacy Program (WRAP) is a developing program with the goal of providing a region-wide, collaborative approach to resource adequacy. The WRAP is administered through a FERC-approved tariff that allows participants to phase into full, binding participation, including being subject to non-compliance charges for failing to meet the requirements of the program. Efforts to launch the binding program have encountered several obstacles. In April 2024, WRAP participants indicated they lacked critical mass to be able to move to the binding phase by Summer 2026. Participants cited challenges that include procuring sufficient firm capacity to meet program requirements and avoid charges. In an effort to move toward a binding program by Summer 2027, WRAP will file tariff changes with FERC that include a temporary reduction of non-compliance charges so participants can fully participate in the program and have access to WRAP capacity reserves on the worst of operating days.

To commit to a resource adequacy program, entities must know what resources they will have to offer. Resource plans that contain large numbers of Tier 2 and Tier 3 resources provide little certainty about future resource capacity, meaning entities cannot be confident in what resources they will have to offer. This may create reticence and, ultimately, delays on the part of entities in joining these programs.





Additional Considerations

Resource adequacy is interwoven with other issues such as transmission planning, policy making, and shifts associated with a changing climate. Each introduces significant risks to reliability.



Transmission Considerations

The modeling tool WECC uses for the Western Assessment transfers electricity between entities when one has a shortfall and the other has sufficient available energy to meet that shortfall.

The analysis in this report differs from that in the Interregional Transfer Capability Study (ITCS), an assessment on which WECC collaborated with NERC and the other Regional Entities to gauge the ability to transfer electricity between regions in the U. S. and Canada, and to determine prudent additions to transfer capability to support reliability. Congress mandated the ITCS in the Fiscal Responsibility Act of 2023. The ability to transfer power between regions could be a key to maintaining reliability amid the changing resource mix and as climate change brings more extreme weather.



Imports

WECC's analysis includes imports, or the ability for entities to transfer electricity between subregions. Studying the ability to import electricity is important because the Western Interconnection was designed to take advantage of its geographic and resource diversity. Imports are critical to reliability, particularly as the variability of the system increases. However, under some extreme conditions, either the resources or the transmission capacity may be reduced or eliminated altogether. Looking at different import scenarios helps WECC better understand the interplay between resource adequacy and transmission availability.

Imports

WECC's analysis includes imports, or the ability for entities to transfer electricity between subregions. Studying the ability to import electricity is important because the Western Interconnection was designed [illegible] of its resources and transmission. Imports are critical to reliab[illegible] increases. However, under some extre[illegible]me conditions, either the resources or the transmission capacity may be reduced or eliminated altogether. Looking at different import scenarios helps WECC better understand the interplay between resource adequacy and transmission availability.

Go here to see how resource adequacy is impacted in each of the five subregions based on the ability to import electricity.

The analysis shows that every subregion relies on the ability to import or transfer electricity, although the impact is much less significant in the DSW and CAMX subregions. The NW-Northwest and NW-Northeast subregions were the most affected in terms of demand at risk, with more than 1,900 hours of demand at risk every year.

For more information about how transfer capability was handled in this assessment, see the appendix.

The analysis shows that every subregion relies on the ability to import or transfer electricity, although the impact is much less significant in the DSW and CAMX subregions. The NW-Northwest and NW-Northeast subregions were the most affected in terms of demand at risk, with more than 1,900 hours of demand at risk every year.

For more information about how transfer capability was handled in this assessment, see the appendix.



Energy Policy

Federal and state policies are driving changes in the electric system. Several states in the West have ambitious clean energy goals, for example, and federal legislation has steered unprecedented amounts of funding to the energy sector.

Together with the Bipartisan Infrastructure Law (BIL), the Inflation Reduction Act (IRA) has accelerated the transformation of the electric grid by making funding available for the development and deployment of clean energy manufacturing facilities and research in the form of tax credits, loans, investments, and other programs.

Batteries and electric vehicles have drawn the most investment—since the IRA's passage, $114 billion in new projects in those industries have been announced, a recent analysis indicates. Also, according to the White House, the U.S. was projected to build more new electric generation capacity in 2024 than has been built in the last two decades, with 96% of that being renewable energy.

At the state level, Washington's Clean Energy Transformation Act requires utilities to supply the state's customers with electricity that is 100% renewable or free of greenhouse gas emissions by 2045. California also has a goal of 100% of its electricity coming from renewable energy and zero-carbon resources by 2045. And Oregon's Clean Energy Targets bill requires the state's electricity providers to significantly reduce the greenhouse gas emissions levels of the electricity sold in the state: 80% below baseline emissions levels by 2030, 90% below baseline emissions levels by 2035, and emissions-free by 2040.

The impact of the IRA was initially expected to be approximately $370 billion in spending and tax credits for clean energy projects over 10 years. That estimate appears low. It could be as high as $1.2 trillion. Since 2022, the IRA has driven approximately $332 billion in new investments in clean energy and transportation technologies nationwide. Nearly all of that was private investment, not government spending, that was sparked by an estimated $48 billion in federal tax credits. Batteries and electric vehicles have drawn the most investments – since the IRA's passage, $114 billion in new projects in those industries have been announced, recent analysis indicates.

Weather

Extreme weather events are increasing in frequency and intensity, in some cases becoming more extreme, unpredictable, widespread, and longer-lasting. These events affect generation, particularly as the resource mix and the demand for electricity becomes more variable. As weather becomes more extreme, what used to be considered extreme is becoming more normal. This is changing how we manage the system.

FERC has approved several new weather-related standards i in recent years, to help close reliability gaps, and utilities and planning entities continue to adapt their projections to account for climate change.

Through its 10-year and 20-year assessments, WECC examines the impact of severe weather on resource adequacy by assessing how the subregions in the Western Interconnection rely on imports to remain resource adequate during events that trigger high demand for electricity. As the climate changes and events become more widespread, it is important to understand how to use the diversity of the interconnection and its evolving resource mix to ensure resource adequacy.

Three new winter reliability standards took effect in April 2023. EOP-011-2 requires generator owners and operators to have cold weather preparedness plans subject to annual inspection. TOP-003-5 and IRO-010-4 direct the creation of databases with information about the operational limitations of generation resources during cold weather conditions.

FERC also approved two new reliability standards in February 2023: EOP-011-3 and EOP-012-1. The standards, which have not taken effect, include new and modified requirements to enhance grid reliability during extreme cold.

And NERC is working on TPL-008-1, which addresses a lack of a long-term planning requirement for extreme heat and cold weather events.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-138:
Department Press Release on Centralia Order

An official website of the United States government Here's how you know

Trump Administration Keeps Coal Plant Open to Ensure Affordable, Reliable and Secure Power in the Northwest

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity.

Energy.gov

March 16, 2026

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access.

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia plant is essential to maintaining grid stability across the Northwest, and this order ensures that the region avoids unnecessary blackout risks and costs.

"The last administration's energy subtraction policies had the United States on track to likely experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," **said Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to power their homes all the time, regardless of whether the wind is blowing or the sun is shining."

Thanks to President Trump's leadership, coal plants across the country are reversing plans to shut down. On December 16, 2025, Secretary Wright issued an emergency order directing TransAlta to keep Unit 2 (729.9 MW) available to operate.
According to DOE's Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

This order is in effect beginning on March 17, 2026, through June 14, 2026.

###

View Previous

Energy Department Approves Immediate Additional LNG Exports from Plaquemines LNG

March 13, 2026

View Next

Energy Department Announces $293 Million in Funding to Support Genesis Mission National Science and Technology Challenges

March 17, 2026

Tags:

COAL ELECTRICITY EMERGENCY RESPONSE

Media Inquiries:

(202) 586-4940 or DOENews@hq.doe.gov

Read more at the energy.gov Newsroom

Follow Us

Open Gov Accessibility Privacy Information Quality No Fear Act Web Policies
Vulnerability Disclosure Program Whistleblower Protection Equal Employment Opportunity Notice of Court Orders

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-139:
Trump Advisor Says Electricity Customers Pay for 202(c) Orders

This copy is for your personal, non-commercial use only. Distribution and use of this material are governed by our Subscriber Agreement and by copyright law. For non-personal use or to order multiple copies, please contact Dow Jones Reprints at 1-800-843-0008 or visit www.djreprints.com.

FEATURE

Who’s Paying to Keep Coal Plants Alive? All Electricity Customers, Trump Advisor Says.

By Laura Sanicola

Jan 14, 2026, 3:27 pm EST



The J.H. Campbell coal-fired power plant in Michigan. Consumers Energy had planned to retire the plant in 2025, but President Trump ordered it to keep operating. (JIM WEST / UCG / GETTY IMAGES)

Key Points

About This Summary

- Federal efforts to keep coal-fired power plants operating beyond planned retirement dates will result in electricity customers bearing the costs.
- The administration's policy aims to prevent an estimated $34 billion to $40 billion in replacement costs if coal plants retire before new resources are ready.
- Some energy experts suggest that delaying coal retirements may be counterproductive and could cost ratepayers $3.1 billion to $5.9 billion annually.

A Trump administration official said Wednesday that efforts to keep coal-fired power plants running beyond their planned retirement dates will ultimately be paid for by electricity customers.

Federal efforts to block coal plant retirements aim to preserve grid reliability amid a surge in electricity demand driven by data centers and artificial intelligence, said Peter Lake, a member of the White House's National Energy Dominance Council, speaking at the American Enterprise Institute's "Powering Prosperity and the New Electricity Economy" conference in Washington.

"All costs end up on ratepayers," Lake said, responding to a question about who pays when utilities are required by the federal government to keep coal plants online after having invested billions of dollars in replacement power generation.

He added that industrial customers typically bear a larger share of those costs, equivalent to about 60%. But it depends on the utility, their generation makeup, and how rate structures allocate expenses based on load size and peak demand.

The Trump administration has so far prevented five coal units from retiring, invoking emergency authorities and directing federal agencies to intervene in power markets. Officials say the U.S. grid cannot afford to lose generation as electricity demand accelerates faster than expected.

The administration has also framed its coal policy as an affordability and reliability measure, aimed at avoiding what Lake said could be $34 billion to $40 billion in replacement costs if operating coal plants were allowed to retire before new dispatcheable resources are in place.

Government estimates call for roughly 100 gigawatts of new power by 2030, a figure Lake compared with adding "California plus two New Yorks" to the grid in less than five years.

"Yes, we need coal. We need gas. We need batteries. Anything with an answer," Lake said.

Coal is getting a boost from AI power and industrial demand. Several utilities, including Duke Energy and some subsidiaries of Southern Company, revised

plans to retire some coal units after forecasting sharp increases in demand from data centers and advanced manufacturing. The changes were approved through state-regulated processes.

But utilities say that being forced to keep some coal plants open is upending years of state-approved planning.

For example, the Michigan-based Campbell coal plant, owned by CMS Energy, was forced by the Trump administration to continue operating into 2026 after being scheduled to retire in 2025, costing about $615,000 a day, according to company filings. The state utility running the plant, Consumers Energy, had already invested in replacement gas generation, renewable contracts, and grid upgrades.

Consumers Energy warned that extending Campbell's operations will adds millions of dollars in incremental fuel, maintenance, and staffing costs that weren't contemplated in approved rates, according to regulatory filings.

Consumers in regulated energy markets may be hit hardest as coal plants stay open longer than planned. A utility that voluntarily plans to delay a plant retirement often gets approval from regulators in a deal that includes freezing rates for consumers and special tariffs that shift costs toward large industrial users like data centers.

That framework can collapse when Washington forces plants to keep operating. When a plant is kept online after replacement assets are already in the rate base, customers effectively pay twice—once for the new plant, and again for the old one.

Some utilities are trying to manage rising AI power needs without passing along costs to households. In Louisiana and parts of the Midwest, for instance, utilities have negotiated special large-load tariffs and contract terms with data-center

customers that include higher base rates, upfront infrastructure contributions, and curtailment provisions during grid stress.

Still, some energy experts say the administration's plans to delay coal retirements may be counterproductive and obscure the more pressing problem: permitting delays to upgrade the grid.

"Mandating that an old power plant operate isn't consistent with a market-based approach," said Rob Gramlich, president of Grid Strategies LLC, at the AEI conference, noting that tens of gigawatts of approved generation remain stalled in interconnection queues due to permitting and transmission constraints.

As my colleague Avi Salzman reported, a study by Grid Strategies, a consultancy funded partly by environmental groups including the Sierra Club, found that the administration's plan to stop fossil fuel plants from closing could cost ratepayers $3.1 to $5.9 billion a year.

Write to Laura Sanicola at laura.sanicola@barrons.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-140:
Department Order No. 202-26-01A

Department of Energy
Washington, DC 20585

Order No. 202-26-01

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 (DOE) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the Electric Reliability Council of Texas, Inc. (ERCOT) region, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. I direct ERCOT (Reliability Coordinator) and its Balancing Authorities and backup generation resources defined below, to comply with this Order.[3] Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Throughout the United States, demand is outpacing generation supply. Generation resource inadequacy is especially problematic during prolonged winter cold snaps. According to the North American Electric Reliability Corporation (NERC), "[w]inter electricity demand is rising at the fastest rate in recent years," and the "total internal demand for the [bulk power system] is forecast to increase by 20.2 GW (2.5%) over last winter's forecast.[4] While NERC assesses that there are "adequate resources for normal winter peak-load conditions," NERC cautions that "more extreme winter conditions extending over a wide area could result in electricity supply shortfalls."[5] According to NERC, areas in the continental United States are at an elevated risk during extreme cold, which jeopardizes American lives, our economy, and national security.[6]

In its 2025–2026 Winter Reliability Assessment, NERC finds that the ERCOT assessment area is at elevated risk. According to NERC, above-normal winter peak and outage

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] For all geographical or electrical areas of the Bulk Power System, all areas are under the oversight of one and only one Reliability Coordinator. NERC Rules of Procedure, section 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *Id.*, section 501.1.4.2. All Loads and generators are under the responsibility and control of one and only one Balancing Authority. *Id.*, section 501.1.4.4.

[4] *2025-2026 Winter Reliability Assessment*, NERC (NERC 2025-2026 Winter Assessment), at 8 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. The NERC 2025-2026 Winter Assessment "identifies, assesses, and reports on areas of concern regarding the reliability of the North American [bulk power system] for the upcoming winter season." *Id*. at 4.

[5] *Id.* at 5.

[6] *Id.* at 6.

conditions could result in the need for operating mitigations and Energy Emergency Alerts (EEAs). NERC states that strong load growth is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For this winter season, NERC explains that ERCOT is expected to continue facing reserve shortage risks, particularly under extreme load conditions that accompany freezing temperatures. NERC cautions that load shedding may be needed under wide-area cold weather events.[7]

Under President Trump's leadership, this administration is determined to take swift and decisive action to protect the American people from tragedies, such as Winter Storm Uri, which resulted in "billions of dollars in damages and over 200 deaths."[8]

In Executive Order 14156, "Declaring a National Energy Emergency," President Trump 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."[9] 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."[10] These Executive Orders underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns.

The Department's 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 systems. "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)

---

[7] NERC, *2025 – 2026 Winter Reliability Assessment*, at 5-6, 31 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[8] *The February 2021 Cold Weather Outages in Texas and the South Central United States*, FERC, NERC, and Regional Entity Staff Report, at 234 (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and. *See id.* at 189 ("Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds.").

[9] 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/.

[10] 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-the-reliability-and-security-of-the-united-states-electric-grid/.

innovation."[11] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and increasing source of load growth.

In July 2025, President Trump released America's AI Action Plan for Winning the Race.[12] It recognizes that the "U.S. electric grid is one of the largest and most complex machines on Earth . . . [that] will need to be upgraded to support data centers and other energy-intensive industries of the future."[13] That plan recommended that we stabilize the grid of today as much as possible, including leveraging extant backup power sources to bolster grid reliability during peak demand and optimize existing grid resources as much as possible, including investigating "new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[14]

NERC-certified Reliability Coordinators and Balancing Authorities[15] are responsible for identifying and addressing emergency conditions on the bulk power system. As discussed below, this is squarely addressed in the mandatory and enforceable NERC Reliability Standard EOP-011-4. Today, calls for voluntary curtailment are authorized under that standard. However, this action gives Reliability Coordinators and Balancing Authorities another tool to avoid the impacts experienced as a result of Winter Storm Uri.

Currently, there are tens of gigawatts of readily available backup generation that have remained largely untapped until now. Deployment of backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites, can prevent avoidable blackouts, thereby saving lives and reducing costs to the American people.

---

[11] Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy at 1(July 2025), https://www.energy.gov/sites/default/files/2025-7/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[12] https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

[13] *Id.* at 15.

[14] *Id.*

[15] The North American Electric Reliability Corporation (NERC) certifies Reliability Coordinators and Balancing Authorities in accordance with its Rules of Procedures.

APPLICATION OF EOP-011-4

Section 215 of the Federal Power Act[16] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[17] because of the significant roles these two functional entity category types have in ensuring bulk power system reliability. A Reliability Coordinator is defined as:

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[18]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."[19]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) . . . ."[20]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 states "[e]ach 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." Balancing Authorities are responsible for

---

[16] 16 U.S.C. § 824o.

[17] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-effective-20231128_with-appendicies.pdf; *see also id.* section 500.

[18] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

[19] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2.

[20] NERC Rules of Procedure, section 501.

requesting that their respective Reliability Coordinators issue an Energy Emergency Alert in accordance with Requirement 2 and Attachment 1 to EOP-011-4. Among other things, Balancing Authorities are authorized to make "[p]ublic appeals for voluntary Load reductions" in Requirement 2.2.4. Balancing Authority Operating plans must include provisions in accordance with Requirement 2.2.9 for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding" and provisions in accordance with Requirement 2.2.10 to determine reliability impacts of cold weather conditions.

According to Requirement 5,

> 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.

According to Requirement 6,

> 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.

Attachment 1 provides,

> **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.

***

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.

***

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.

***

3.3.1 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.

Of particular note, NERC's 2025-2026 Winter Assessment recognizes that "[p]roactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters."[21] NERC further cautions that Reliability Coordinators and Balancing Authorities "should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions."[22]

EMERGENCY SITUATION

Winter Storm Fern poses significant risks to electric reliability in the Reliability Coordinator's footprint. Consistent with NERC's cautionary notes and this Administration's commitment to grid stability, this order seeks to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk power system. The employment of this backup generation is expected to reduce stress on the grid. This will permit orderly, safe, and secure operations during Winter Storm Fern.

Consistent with my letter issued on January 22, 2026, ERCOT requested today that DOE issue an order pursuant to FPA section 202(c) to allow the deployment of backup generation during emergency conditions.

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

[21] NERC 2025-2026 Winter Assessment at 7.

[22] *Id*.

transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[23] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

I have made the determination that an emergency exists, due to an abrupt, unexpected increase in demand for electric energy relative to prior forecasts, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. As discussed above, taking into account the historical data, past projections and planning, and the projections for the upcoming winter season, together with the increasing demand for electricity that has substantially outpaced net generating capacity additions, a statutory emergency exists this winter across the continental United States. As noted above, NERC has warned that winter electricity demand is rising at the fastest rate in recent years and the total internal demand for the bulk power system is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. Even prolonged cold snaps can be expected to lead to the potential 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 during the upcoming winter.

To best meet the emergency and serve the public interest, backup generation resources shall be made available to run during the emergency conditions specified below.

Based on my determination of an emergency set forth above, I hereby order:

A. From January 24, 2026, the Reliability Coordinator and its Balancing Authorities are authorized to direct backup generation resources at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3.[24]

B. This Order requires the operation of the backup generation resources described in paragraph A. Following the conclusion of the EEA conditions described in paragraph A, sufficient time for orderly ramp down is permitted, consistent with industry practices.

[23] 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).

[24] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.").

C. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

D. To minimize adverse environmental impacts, this Order limits operation of deployed units to the times and within the parameters as determined by the Reliability Coordinator and its Balancing Authorities pursuant to paragraphs A-C.

E. All operations of backup generation resources authorized under this order must otherwise comply with ancillary 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.

F. ERCOT shall provide notification to the Department (via AskCR@hq.doe.gov) within one day following the date any backup generation resources have been directed to operate pursuant to this Order. The reporting shall include a list of all backup generation resources directed to operate pursuant to this Order. ERCOT shall provide such additional information regarding the environmental and other impacts of this Order and their compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

G. Each party affected by this order is directed to file with the Federal Energy Regulatory Commission any tariff, tariff revisions or waivers necessary to effectuate this Order, as applicable. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

H. This Order shall not preclude the need for the backup generation resources subject to this Order to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

I. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, any backup generation resource subject to this Order shall not be considered a capacity resource.

J. This Order shall be effective upon its issuance, and shall expire at 11:59 PM EST on January 27, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:34 PM EST on this 24th day of January 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

State Commissioners
See Attachment A

Attachment A: State Contact Information

The table below provides contact information for state commissioners within the NERC Reliability Coordinator.

State	Office	Name
TX	Public Utility Commission of Texas	Thomas Gleeson
		Kathleen Jackson
	Railroad Commission of Texas	Christi Craddick
		Wayne Christian
		Jim Wright

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-141:
Department Order No. 202-26-01A

Department of Energy
Washington, DC 20585

Amended Order No. 202-26-01A

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 (DOE) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the Electric Reliability Council of Texas, Inc. (ERCOT) region, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. I direct ERCOT (Reliability Coordinator) and its Balancing Authorities and backup generation resources defined below, to comply with this Order.[3] Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Throughout the United States, demand is outpacing generation supply. Generation resource inadequacy is especially problematic during prolonged winter cold snaps. According to the North American Electric Reliability Corporation (NERC), "[w]inter electricity demand is rising at the fastest rate in recent years," and the "total internal demand for the [bulk power system] is forecast to increase by 20.2 GW (2.5%) over last winter's forecast.[4] While NERC assesses that there are "adequate resources for normal winter peak-load conditions," NERC cautions that "more extreme winter conditions extending over a wide area could result in electricity supply shortfalls."[5] According to NERC, areas in the continental United States are at an elevated risk during extreme cold, which jeopardizes American lives, our economy, and national security.[6]

In its 2025–2026 Winter Reliability Assessment, NERC finds that the ERCOT assessment area is at elevated risk. According to NERC, above-normal winter peak and outage

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] For all geographical or electrical areas of the Bulk Power System, all areas are under the oversight of one and only one Reliability Coordinator. NERC Rules of Procedure, section 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *Id.*, section 501.1.4.2. All Loads and generators are under the responsibility and control of one and only one Balancing Authority. *Id.*, section 501.1.4.4.

[4] *2025-2026 Winter Reliability Assessment*, NERC (NERC 2025-2026 Winter Assessment), at 8 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. The NERC 2025-2026 Winter Assessment "identifies, assesses, and reports on areas of concern regarding the reliability of the North American [bulk power system] for the upcoming winter season." *Id*. at 4.

[5] *Id.* at 5.

[6] *Id.* at 6.

conditions could result in the need for operating mitigations and Energy Emergency Alerts (EEAs). NERC states that strong load growth is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For this winter season, NERC explains that ERCOT is expected to continue facing reserve shortage risks, particularly under extreme load conditions that accompany freezing temperatures. NERC cautions that load shedding may be needed under wide-area cold weather events.[7]

Under President Trump's leadership, this administration is determined to take swift and decisive action to protect the American people from tragedies, such as Winter Storm Uri, which resulted in "billions of dollars in damages and over 200 deaths."[8]

In Executive Order 14156, "Declaring a National Energy Emergency," President Trump 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."[9] 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."[10] These Executive Orders underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns.

The Department's 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 systems. "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)

---

[7] NERC, *2025 – 2026 Winter Reliability Assessment*, at 5-6, 31 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[8] *The February 2021 Cold Weather Outages in Texas and the South Central United States*, FERC, NERC, and Regional Entity Staff Report, at 234 (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and. *See id.* at 189 ("Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds.").

[9] 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/.

[10] 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-the-reliability-and-security-of-the-united-states-electric-grid/.

innovation."[11] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and increasing source of load growth.

In July 2025, President Trump released America's AI Action Plan for Winning the Race.[12] It recognizes that the "U.S. electric grid is one of the largest and most complex machines on Earth . . . [that] will need to be upgraded to support data centers and other energy-intensive industries of the future."[13] That plan recommended that we stabilize the grid of today as much as possible, including leveraging extant backup power sources to bolster grid reliability during peak demand and optimize existing grid resources as much as possible, including investigating "new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[14]

NERC-certified Reliability Coordinators and Balancing Authorities[15] are responsible for identifying and addressing emergency conditions on the bulk power system. As discussed below, this is squarely addressed in the mandatory and enforceable NERC Reliability Standard EOP-011-4. Today, calls for voluntary curtailment are authorized under that standard. However, this action gives Reliability Coordinators and Balancing Authorities another tool to avoid the impacts experienced as a result of Winter Storm Uri.

Currently, there are tens of gigawatts of readily available backup generation that have remained largely untapped until now. Deployment of backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites, can prevent avoidable blackouts, thereby saving lives and reducing costs to the American people.

---

[11] Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy at 1(July 2025), https://www.energy.gov/sites/default/files/2025-7/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[12] https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

[13] *Id.* at 15.

[14] *Id.*

[15] The North American Electric Reliability Corporation (NERC) certifies Reliability Coordinators and Balancing Authorities in accordance with its Rules of Procedures.

APPLICATION OF EOP-011-4

Section 215 of the Federal Power Act[16] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[17] because of the significant roles these two functional entity category types have in ensuring bulk power system reliability. A Reliability Coordinator is defined as:

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[18]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."[19]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) . . . ."[20]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 states "[e]ach 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." Balancing Authorities are responsible for

---

[16] 16 U.S.C. § 824o.

[17] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-effective-20231128_with-appendicies.pdf; *see also id.* section 500.

[18] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

[19] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2.

[20] NERC Rules of Procedure, section 501.

requesting that their respective Reliability Coordinators issue an Energy Emergency Alert in accordance with Requirement 2 and Attachment 1 to EOP-011-4. Among other things, Balancing Authorities are authorized to make "[p]ublic appeals for voluntary Load reductions" in Requirement 2.2.4. Balancing Authority Operating plans must include provisions in accordance with Requirement 2.2.9 for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding" and provisions in accordance with Requirement 2.2.10 to determine reliability impacts of cold weather conditions.

According to Requirement 5,

> 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.

According to Requirement 6,

> 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.

Attachment 1 provides,

> **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.

***

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.

***

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.

***

3.3.1 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.

Of particular note, NERC's 2025-2026 Winter Assessment recognizes that "[p]roactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters."[21] NERC further cautions that Reliability Coordinators and Balancing Authorities "should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions."[22]

EMERGENCY SITUATION

Winter Storm Fern poses significant risks to electric reliability in the Reliability Coordinator's footprint. Consistent with NERC's cautionary notes and this Administration's commitment to grid stability, this order seeks to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk power system. The employment of this backup generation is expected to reduce stress on the grid. This will permit orderly, safe, and secure operations during Winter Storm Fern.

Consistent with my letter issued on January 22, 2026, ERCOT requested today that DOE issue an order pursuant to FPA section 202(c) to allow the deployment of backup generation during emergency conditions.

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

[21] NERC 2025-2026 Winter Assessment at 7.

[22] *Id*.

transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[23] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

I have made the determination that an emergency exists, due to an abrupt, unexpected increase in demand for electric energy relative to prior forecasts, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. As discussed above, taking into account the historical data, past projections and planning, and the projections for the upcoming winter season, together with the increasing demand for electricity that has substantially outpaced net generating capacity additions, a statutory emergency exists this winter across the continental United States. As noted above, NERC has warned that winter electricity demand is rising at the fastest rate in recent years and the total internal demand for the bulk power system is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. Even prolonged cold snaps can be expected to lead to the potential 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 during the upcoming winter.

To best meet the emergency and serve the public interest, backup generation resources shall be made available to run during the emergency conditions specified below.

Based on my determination of an emergency set forth above, I hereby order:

A. From January 24, 2026, the Reliability Coordinator and its Balancing Authorities are authorized to direct backup generation resources at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate after ERCOT deploys all available market services, except for frequency responsive services, before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3.[24]

B. This Order requires the operation of the backup generation resources described in

[23] 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).

[24] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2."). *Cf.* Tex. Util. Code § 37.0561(e) ("After the independent organization deploys all available market services, except for frequency responsive services, the independent organization may direct the applicable electric utility or municipally owned utility to require the large load customer to either deploy the customer's on-site backup generating facilities or curtail load. The independent organization shall include a deployment under this section as firm load shed when calculating any price adjustments for reliability deployments.").

paragraph A. Following the conclusion of the EEA conditions described in paragraph A, sufficient time for orderly ramp down is permitted, consistent with industry practices.

C. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

D. To minimize adverse environmental impacts, this Order limits operation of deployed units to the times and within the parameters as determined by the Reliability Coordinator and its Balancing Authorities pursuant to paragraphs A-C.

E. All operations of backup generation resources authorized under this order must otherwise comply with ancillary 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.

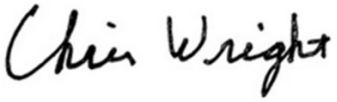
F. ERCOT shall provide notification to the Department (via AskCR@hq.doe.gov) within one day following the date any backup generation resources have been directed to operate pursuant to this Order. The reporting shall include a list of all backup generation resources directed to operate pursuant to this Order. ERCOT shall provide such additional information regarding the environmental and other impacts of this Order and their compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

G. This Order shall not preclude the need for the backup generation resources subject to this Order 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, any backup generation resource subject to this Order shall not be considered a capacity resource.

I. This Order shall be effective upon its issuance, and shall expire at 11:59 PM EST on January 27, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 1:46 PM EST on this 25th day of January 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

State Commissioners
See Attachment A

Attachment A: State Contact Information

The table below provides contact information for state commissioners within the NERC Reliability Coordinator.

State	Office	Name
TX	Public Utility Commission of Texas	Thomas Gleeson
		Kathleen Jackson
		Courtney K. Hjaltman
		Morgan Johnson
	Railroad Commission of Texas	Christi Craddick
		Wayne Christian
		Jim Wright

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-142:
Department Order No. 202-26-03

Department of Energy
Washington, DC 20585

Order No. 202-26-03

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 (DOE) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists within the ISO New England Inc. (ISO-NE) service territory 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.

Emergency Situation

On January 25, 2026, ISO-NE, the Regional Transmission Organization (RTO) spanning six states,[3] filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act,* (Application) with DOE.[4] ISO-NE has indicated that "[i]n many parts of the ISO-NE Balancing Authority Area, temperatures for January 25, 26, and 27, 2026 are forecasted to drop well below average, and abnormally low temperatures are expected to persist through January 30, 2026."[5] As of the time of filing its Application, ISO-NE is anticipating a "sustained high level of demand for electricity."[6] According to ISO-NE, "[w]hile the vast majority of generating units in the ISO-NE region continue to function adequately, some units may experience difficulty due to emissions/air permitting limitations, or other operating constraints."[7] ISO-NE states that all generating resources may be needed to meet the expected demand of the cold weather event.[8]

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The six states are Connecticut, Rhode Island, Maine, Massachusetts, New Hampshire, and Vermont.

[4] Application at 1.

[5] *Id.* at 2.

[6] *Id.*

[7] *Id.*

[8] *Id.*

Description of Mitigation Measures

In anticipation of the cold weather event, ISO-NE states that it already issued a cold weather watch.[9] ISO-NE has also indicated that it is prepared to employ measures in its Operating Procedures designed to address abnormal conditions or deficiencies to "ensure the supply of generation will continue to be sufficient to meet demand and reserve."[10]

Request for Order

ISO-NE requests that the Secretary issue an order effective immediately and through January 31, 2026, the expected period to address high load related to Winter Storm Fern, authorizing "the provision of additional energy from all [Specified Resources], as well as any other generating units subject to emissions or other permit limitations."[11] The generating units (Specified Resources) to which this Order related are listed in Exhibit A of the Application for instant Order 202-26-3, as described below.

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."[12] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

Given the emergency caused by the expected load stress, the responsibility of ISO-NE to ensure maximum reliability on its system, and the ability of ISO-NE to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the expected load stress, shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes by Winter Storm Fern and its aftermath, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

---

[9] *Id.* at 2-3.

[10] *Id*. at 2.

[11] *Id.*

[12] 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).

Consistent with the anticipated circumstances, this Order is limited to the period of time that Winter Storm Fern is expected to impact the ISO-NE service territory. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation under the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ISO-NE anticipates that this Order may result in exceedance of permit restrictions on emissions, effluent, or other environmental permit limitations.[13] To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ISO-NE for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. In the event that ISO-NE determines that generation from the Specified Resources is necessary to meet the electricity demand that ISO-NE anticipates in its service territory, I direct ISO-NE to dispatch such unit or units and to order their operation only as needed to maintain reliability. Specified Resources are those generating units set forth in Exhibit A to their Application for the instant order (i.e., Order 202-26-3 Resource List), subject to updates directed here and as described in paragraph D, which DOE shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ISO-NE for maintaining grid reliability and to the maximum extent practicable is consistent with any applicable environmental law. ISO-NE shall provide a daily notification to DOE (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource 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. In the event that ISO-NE identifies additional generation units that it deems necessary to maintain the reliability of the power grid, ISO-NE shall provide prompt written

[13] *Id*. at 1, 4.

notice to DOE at AskCR@hq.doe.gov with the name and location of those units that ISO-NE has identified. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to DOE updating Exhibit A of the Application, and ISO-NE may dispatch such additional generation units, provided that if the DOE notifies ISO-NE that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from DOE.

E. ISO-NE 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 DOE from time to time.

F. This Order shall not preclude the need for the Specified Resources to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 11:59PM EST on January 31, 2026, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 7:38 AM EST on this 25th day of January 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

State Commissioners
See Attachment A

Attachment A: State Contact Information

The table below provides contact information for state commissioners within ISO-NE.

State	Office	Name
CT	Connecticut Public Utilities Regulatory Authority	Thomas Wiehl
		David Arconti
		Janice Beecher
		Holly Cheeseman
		Everett Smith
RI	Rhode Island Public Utilities Commission	Ronald T. Gerwatowski
		Abigail Anthony
		Karen Bradbury
MA	Massachusetts Department of Public Utilities	Jeremy McDiarmid
		Staci Rubin
		Elizabeth Anderson
	Massachusetts Department of Telecommunications and Cable	Karen Charles
VT	Vermont Public Utility Commission	Ed McNamara
		Riley Allen
		Margaret Cheney
	Vermont Department of Public Service	Kerrick Johnson
NH	New Hampshire Public Utilities Commission	Pradip Chattopadhyay
		Mark W. Dell'Orfano
	New Hampshire Department of Energy	Jared S. Chicoine
ME	Maine Public Utilities Commission	Philip L. Bartlett
		Carrie Gilbert
		Patrick Scully

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-143:
Department Order No. 202-22-2 Amendment No. 1

Department of Energy
Washington, DC 20585

Amendment Number 1 to Order No. 202-22-2

On September 4, 2022, because of a shortage of currently operational electric generating facilities, high demand for electricity, and other adverse conditions resulting from the extreme heat event in California, I issued Order No. 202-22-2. Order No. 202-22-2 authorized the Balancing Authority of Northern California (BANC) to direct the identified electric generating resource (Covered Resources) to operate in BANC's Balancing Authority Area (BAA), under specified conditions, to prevent or mitigate potential power disruptions and provide relief to the bulk power system during stressed grid conditions caused by extreme heat until September 8, 2022. Order No. 202-22-2 expires at the end of the day on September 8, 2022, by its own terms.

On September 7, 2022, BANC submitted a *Request for Extension and Limited Amendment of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Renewal Application) to the Department. In its Renewal Application, BANC requests an extension of Order 202-22-1 through September 11, 2022 and certain modifications to the run time hour limitations contained in Order No. 202-22-2. On September 8, 2022, BANC filed a Revised Request for *Request for Extension and Limited Amendment of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* in response to questions from DOE.

Emergency Situation

In its Renewal Application, BANC states that "the actual heat event has been more severe and records loads have been experienced." The emergency conditions brought about by the ongoing extreme heat event in California have continued and worsened and the supply of electricity is at increased risk for meeting system demand. As stated in its Renewal Application, BANC established a new record peak of approximately 4943 MW on September 6. BANC entered into an EEA-2 as of 1330 hours that same day. During this period BANC had forced outages of significant generation but was able to return units to service in approximately 90 minutes. It is believed that BANC members Roseville and Modesto exceeded their all-time peaks. Consequently, BANC requests the expiration date of Order No. 202-22-2 be extended through September 11, 2022.

In addition to the extension of Order No. 202-22-2, BANC has requested that the Order be modified to remove the 2 PM to 10 PM run time limitation so as to allow additional operational flexibility. BANC specifically requests that the Covered Resource be allowed to run during anytime that they have received notice of an Energy Emergency Alert Level 2 (EEA2) condition or greater. The practical impact of this will be to allow the Covered Resource more notice to follow their protocols for ramping up their diesel-fired generator units. In addition, BANC has requested the ramp down of the Covered Resource could extend beyond the period in which the EEA 2 condition exists. Specifically, the ramp down would commence at the time the EEA 2 condition is declared ended and should be completed as soon as possible consistent with good utility and operational

Consultation

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The Environmental Protection Agency (EPA) is the primary federal agency in this case with expertise in the protected environmental interest, specifically Title V of the Clean Air Act and the Department consulted with EPA after receiving the Renewal Application and EPA did not request any additional conditions be included in this Order. Email from Acting Assistant Administrator Larry Starfield, EPA Office of Enforcement and Compliance Assurance to Kathleen Hogan, Acting Under Secretary for Infrastructure for DOE, September 7, 2022.

Based on the information submitted to the Department, I have determined that an emergency continues to exist in California due to a shortage of electric energy. I find that the issuance of this Order will help to meet the emergency conditions and serve the public interest as required by FPA section 202(c).

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the FPA, I hereby grant BANC's Renewal Application and issue this Order, with modifications as explained below, to extend the expiration date of Order No. 202-22-2 through September 11, 2022.

1. Ordering Paragraph A appearing on page 4 of Order No. 202-22-2 is hereby deleted and replaced in its entirety by the following:

   A. From September 8, 2022, to September 11, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the notification of an Energy Emergency Alert Level 2[1] condition or greater after exhausting all reasonably and practically available resources, together with such reasonable and limited time as is necessary for a Covered Resource to ramp down following an Energy Emergency Alert Level 2 or greater, consistent with good utility practice as directed by the BANC with the goal of limited operation outside of an Energy Emergency Alert Level 2 or greater to the greatest extent possible.

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

2. The date September 8, 2022 where it appears in Ordering Paragraphs D and H of Order No. 202-22-2 is hereby replaced by the date September 11, 2022.

3. All other terms of Order No. 202-22-2 remain the same and in effect, including Ordering Paragraphs A-H, except as modified herein.

4. This Amendment Number 1 to Order No. 202-22-2 shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 11, 2022.

Issued in Washington, D.C. at 16:38 Eastern Time on this 8th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-144:
Department Order No. 202-22-1 Amendment No. 2

Department of Energy
Washington, DC 20585

Amendment Number 2 to Order No. 202-22-1

On September 2, 2022, because of a shortage of currently operational electric generating facilities, high demand for electricity, and other adverse conditions resulting from the extreme heat event in California, I issued Order No. 202-22-1. Order No. 202-22-1 authorizes the California Independent System Operator Corporation (CAISO), to direct the operation of the Covered Resources identified in Order No. 202-22-1 and on the terms set forth therein. On September 7, 2022, because of the continuing shortage of electric energy and the need for continued operation of the two units at Calpine's Greenleaf Unit 1 site in Yuba City, California (Greenleaf Units), I issued Amendment No. 1 to Order No. 202-22-1. Amendment No. 1 to Order No. 202-22-1 added the Greenleaf Units as Covered Resources subject to the terms of Order No. 202-22-1, except that the Greenleaf Units may be operated through September 9, 2022. By its terms, Order No. 202-22-1 as amended by Amendment No. 1 expires at the end of the day on September 8, 2022 with respect to the Covered Resources other than the Greenleaf Units, and at the end of the day on September 9, 2022 with respect to the Greenleaf Units. Order No. 202-22-1 as amended by Amendment No. 1 is sometimes referred to herein as Amended Order No. 202-22-1.

On September 7, 2022, CAISO submitted a *Request for Extension of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Renewal Application) to the Department. In its Renewal Application, CAISO requests an extension of the expiration date of Order No. 202-22-1 through September 12, 2022.

Emergency Situation

In its Renewal Application, CAISO states that California is experiencing extreme heat, which the CAISO forecasts to continue through at least September 9, 2022. Further, CAISO explains that unpredictable conditions could exacerbate grid reliability issues at any time. The threat of wildfire to the reliable operation of the bulk power system remains significant, and drought conditions are affecting the availability of hydroelectric power. Ambient conditions facing generating facilities are causing de-rates at some units and forcing other units offline. Wildfire threats arising from the extreme heat event are unpredictable and could force transmission and resources out of service. Consequently, the CAISO believes it prudent to ask that the expiration date of Order No. 202-22-1 be extended through September 12, 2022.

Consultation

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The Environmental

Protection Agency (EPA) is the primary federal agency in this case with expertise in the protected environmental interest, specifically Title V of the Clean Air Act and the Department consulted with EPA after receiving the Renewal Application and EPA did not request any additional conditions be included in this Order. Email from Acting Assistant Administrator Larry Starfield, EPA Office of Enforcement and Compliance Assurance to Kathleen Hogan, Acting Under Secretary for Infrastructure for DOE, September 7, 2022.

Based on the information submitted to the Department, I have determined that an emergency continues to exist in California due to a shortage of electric energy. I find that the issuance of this Order will help to meet the emergency conditions and serve the public interest as required by FPA section 202(c).

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the FPA, I hereby grant CAISO's Renewal Application and issue this Order to extend the expiration date of Amended Order No. 202-22-1 through September 12, 2022.

1. In accordance with the foregoing, (a) the date September 8, 2022 where it appears in Ordering Paragraphs A, D, and H of Order No. 202-22-1 is hereby replaced by the date September 12, 2022, and (b) the date September 9, 2022 where it appears in the Ordering Paragraph of Amendment No. 1 to Order No. 202-22-1 is hereby replaced by the date September 12, 2022.

2. All other terms of Amended Order No. 202-22-1 remain the same and in effect, including Ordering Paragraphs A-H, except as modified herein.

3. This Amendment Number 2 to Order No. 202-22-1 shall be effective upon its issuance and shall expire at 23:59 Pacific Time on September 12, 2022.

Issued in Washington, D.C. at 15:52 Eastern Time on this 8th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-145:
Starfield Email to Hoffman

From: Starfield, Lawrence <Starfield.Lawrence@epa.gov>
Date: Monday, Sep 11, 2017, 11:27 AM
To: Hoffman, Patricia <Pat.Hoffman@hq.doe.gov>
Cc: Lucas, John T. <John.T.Lucas@hq.doe.gov>, Minoli, Kevin <Minoli.Kevin@epa.gov>, Kelley, Rosemarie <Kelley.Rosemarie@epa.gov>, Chapman, Apple <Chapman.Apple@epa.gov>
Subject: DOE section 202(c) order

To: Pat Hoffman, DOE Acting Under Secretary for Science and Energy

On August 24, 2017, PJM submitted a renewal application requesting a 90-day renewal of the Order issued on June 16, 2017, by the Secretary of Energy. This email confirms that the Department of Energy (DOE) consulted with the Environmental Protection Agency (EPA), the primary Federal agency with expertise in the Mercury and Air Toxics Standard and section 316(b) of the Clean Water Act, with respect to a renewal order under Section 202(c) of the Federal Power Act related to Virginia Electric and Power Company's Units 1 and 2 at its Yorktown Power Station, near Yorktown, Virginia. See 16 U.S.C. § 824a(c)(4)(B) (Federal Power Act, Section 202(c)(4)(B)). DOE's proposed operational conditions for the order are generally consistent with EPA's Administrative Compliance Order, AED-CAA-113(a)-2016-002, as amended.

Thank you for your coordination on this matter.

Larry Starfield
Acting Assistant Administrator
Office of Enforcement and Compliance Assurance
U.S. EPA
Washington, DC

(202) 564-2440 (office)
(202) 564-8179 (direct)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-146:
NERC 2025 Long-Term Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



Table of Contents

Preface 3
About This Assessment 4
Reading This Report 5
Executive Summary 6
Capacity and Energy Risk Assessment 6
Trends and Reliability Implications 9
Recommendations 10
Capacity and Energy Risk Assessment 12
Assessment Approach 12
Risk Categories 12
Resource and Demand Projections 23
Reducing Resource Capacity and Energy Risk 24
Demand Trends and Implications 25
Demand and Energy Projections 25
Reliability Implications 29
Resource Mix Changes 30
Planned On-Peak Capacity Additions 31
Transmission Development and Interregional Transfer Capability 37
Transmission Projects 37
Interregional Transfer Capability Study (Canadian Analysis) 38
Regional Assessments Dashboards 41
MISO 42
MRO-Manitoba Hydro 49
MRO-SaskPower 54
MRO-SPP 59
NPCC-Maritimes 63
NPCC-New England 68
NPCC-New York 74
NPCC-Ontario 80
NPCC-Québec 86
PJM 90
SERC-Central 95
SERC-East 102
SERC-Florida Peninsula 112
SERC-Southeast 120
Texas RE-ERCOT 128
WECC-Alberta 134
WECC-Basin 138
WECC-British Columbia 143
WECC-California 147
WECC-Mexico 151
WECC-Northwest 154
WECC-Rocky Mountain 159
WECC-Southwest 163
Demand Assumptions and Resource Categories 167
Methods and Assumptions 171
Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area 175
Recommendations and ERO Actions Summary 177

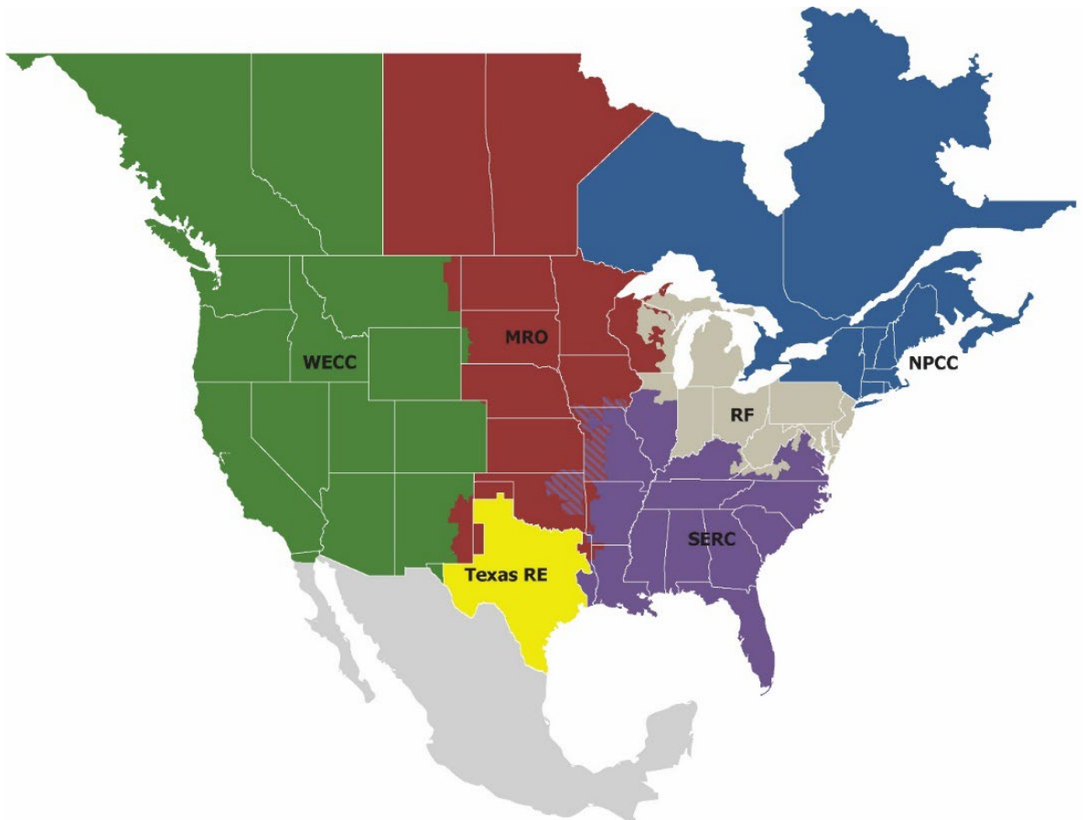
Preface

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.

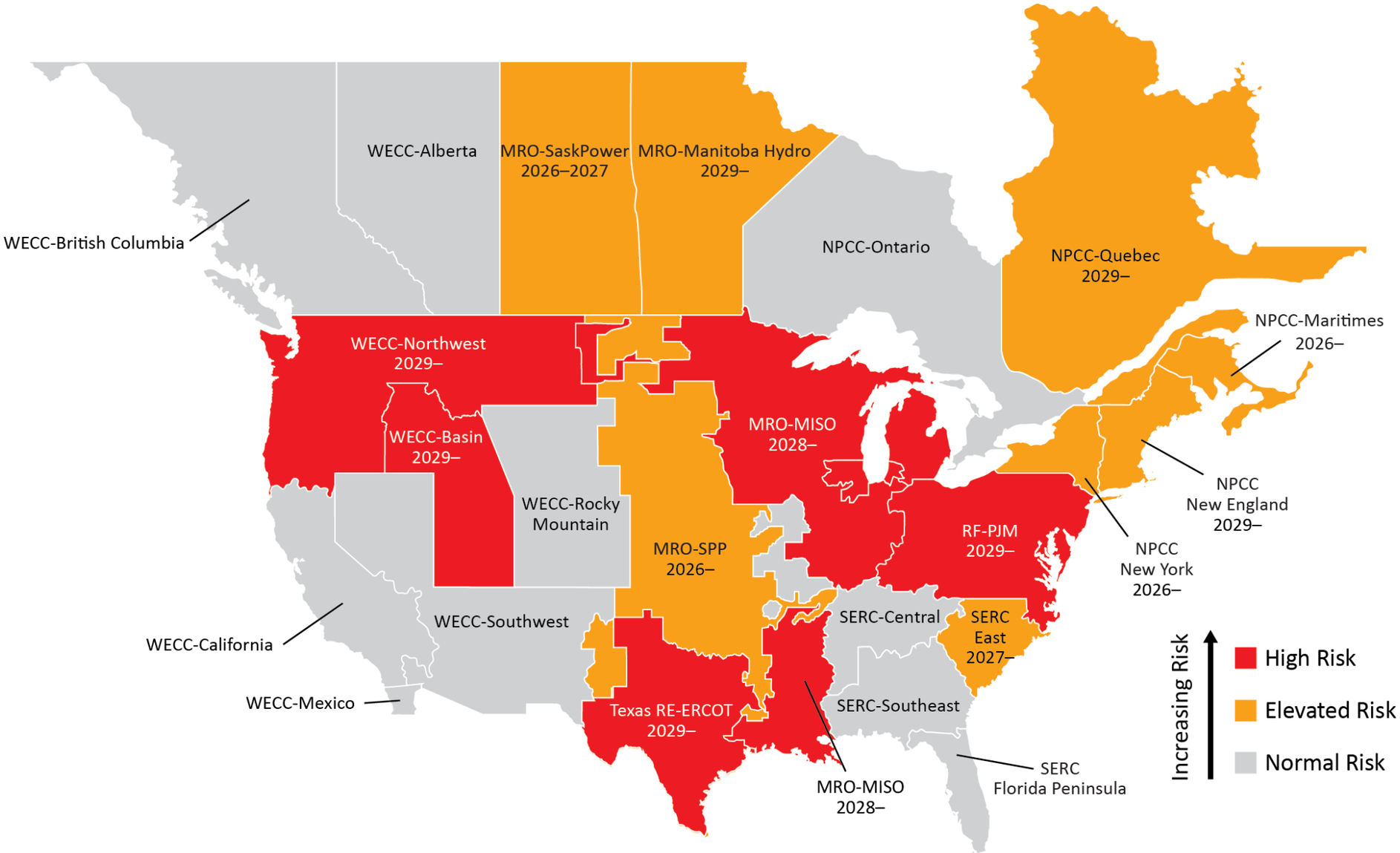


Figure 1: Risk Area Summary 2026–2030

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.

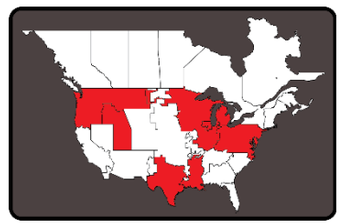
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

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.

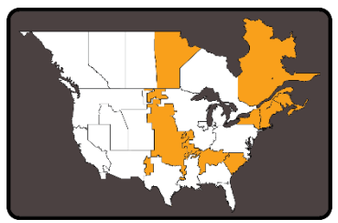
For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- 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*.

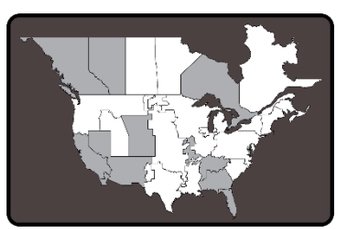
- Resource adequacy target(s) established by regulatory authority or system operator are not met.

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.

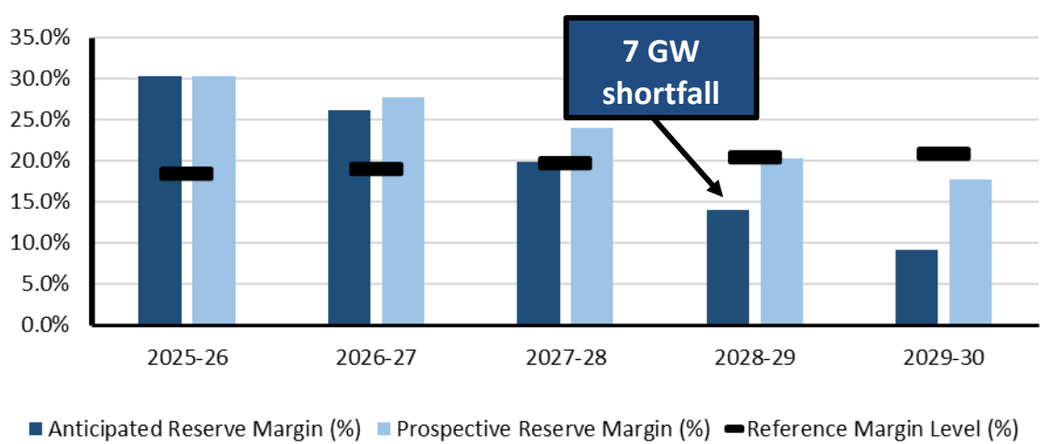
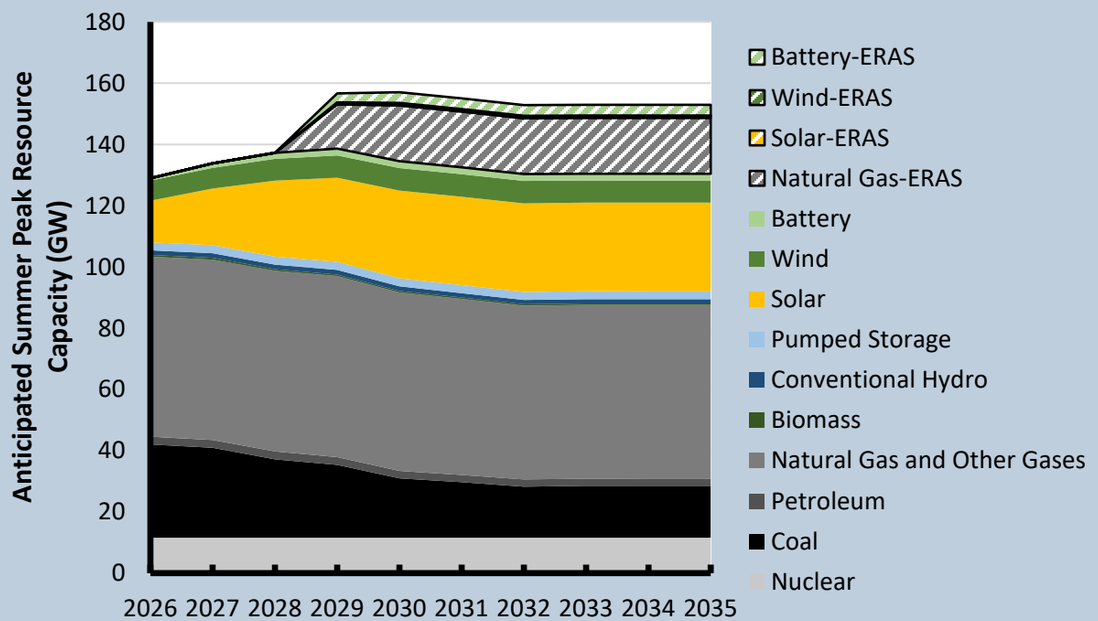


Figure 2: MISO Winter Planning Reserve Margins

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**).

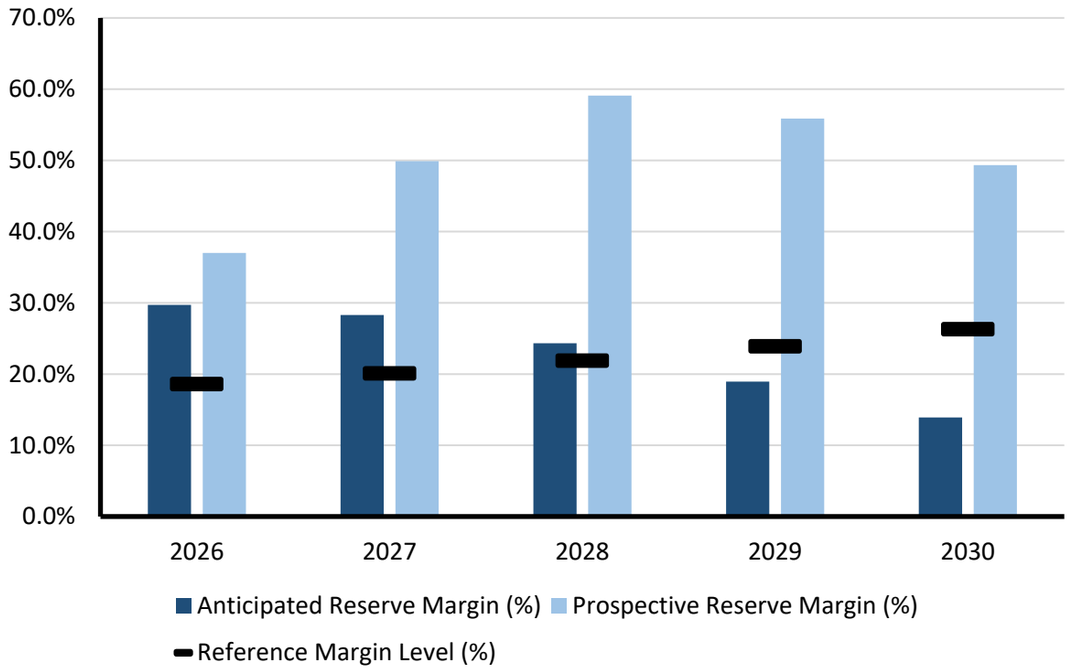


Figure 3: PJM Summer Planning Reserve Margins

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**).

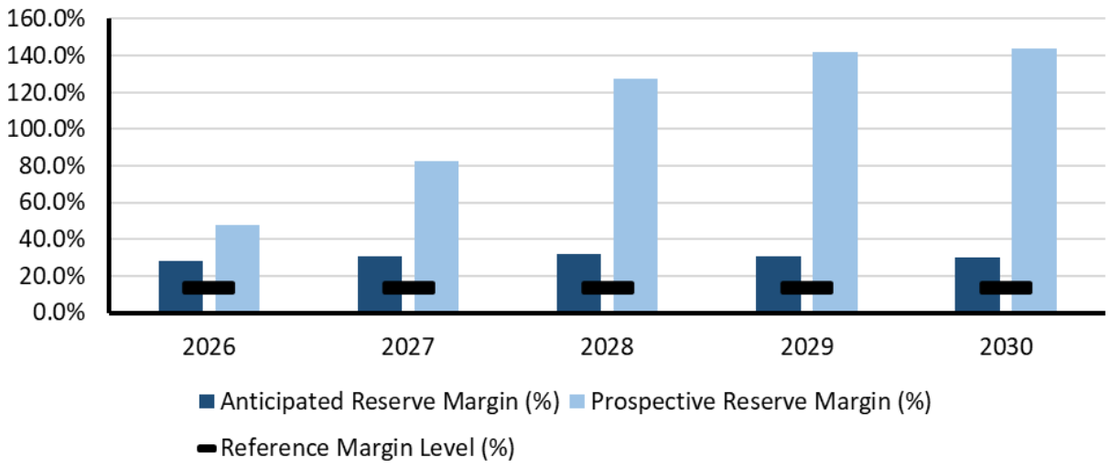


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

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.

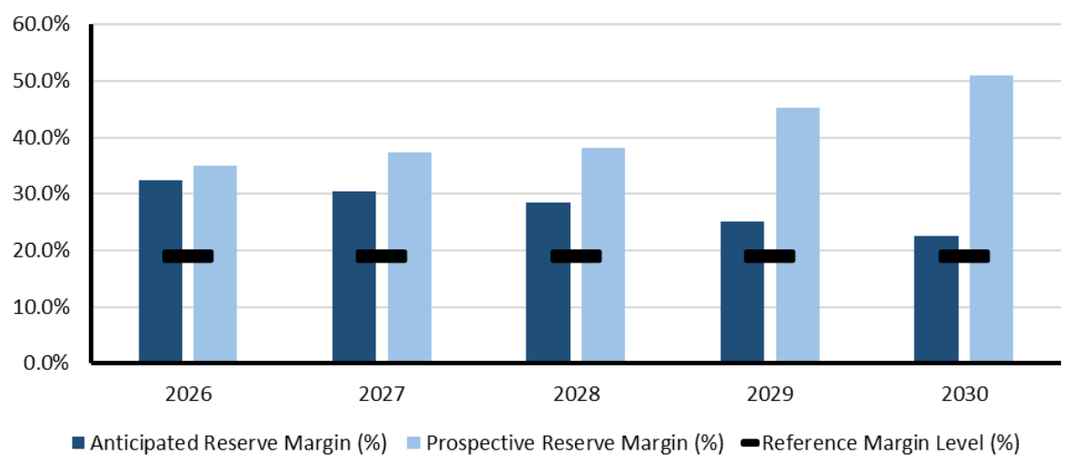


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

[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.

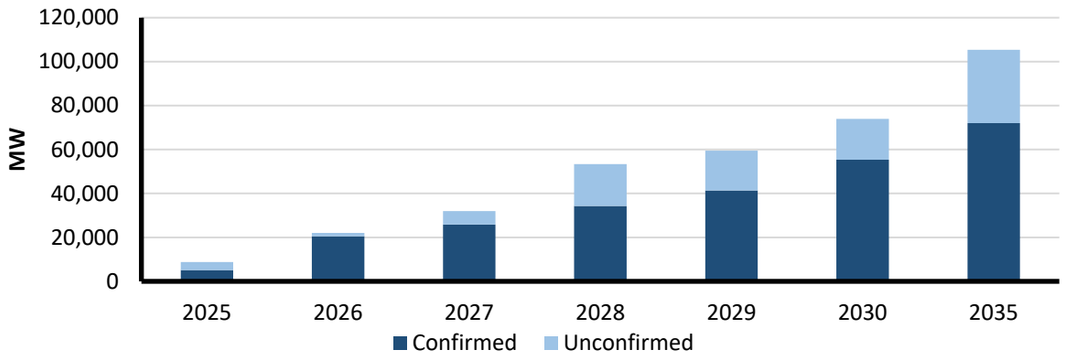


Figure 6: Projected Generation Retirement Capacity Through 2035

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.

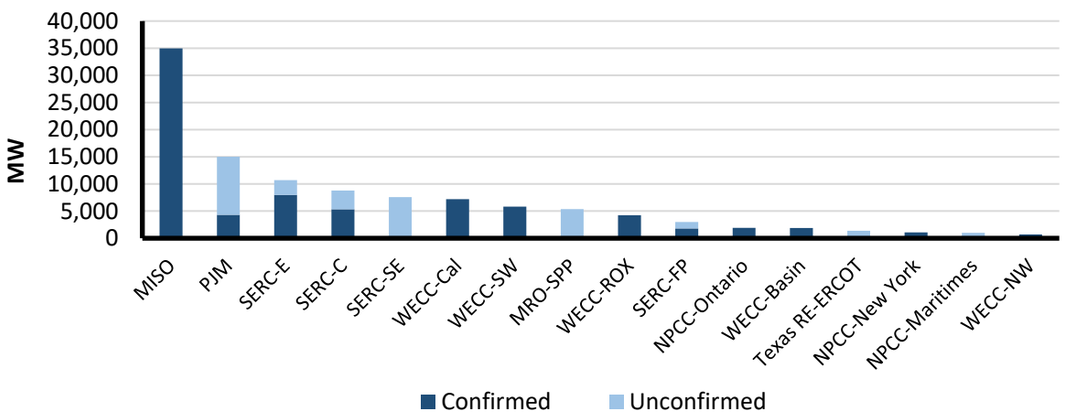


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

[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.**

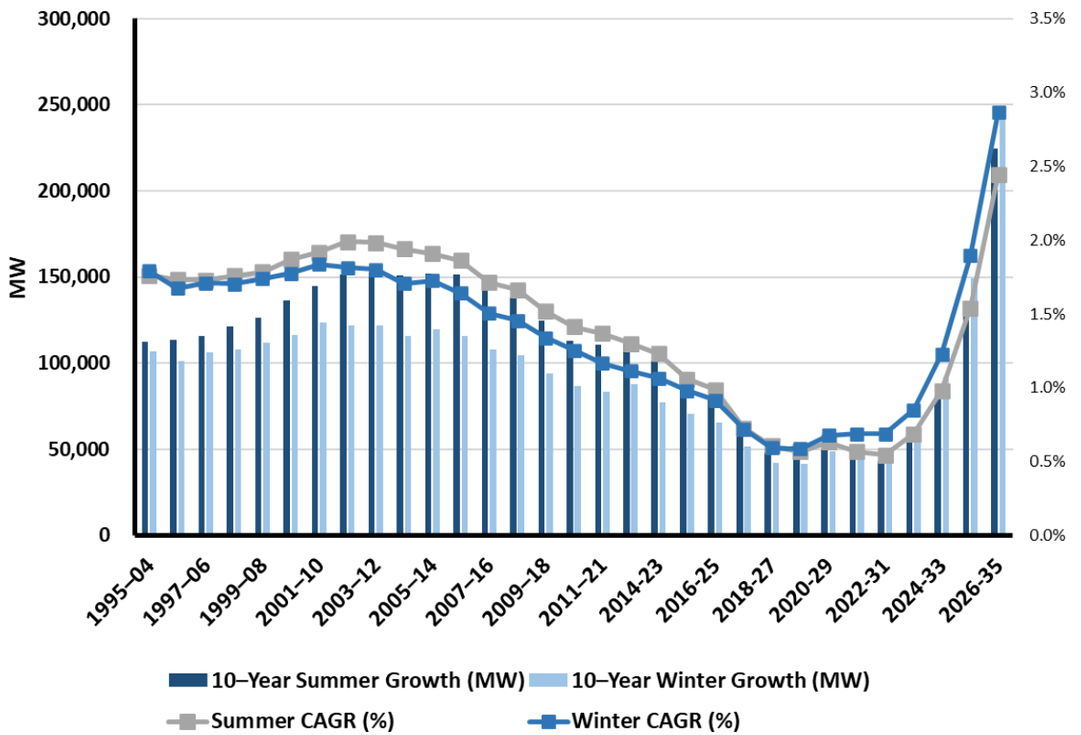


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

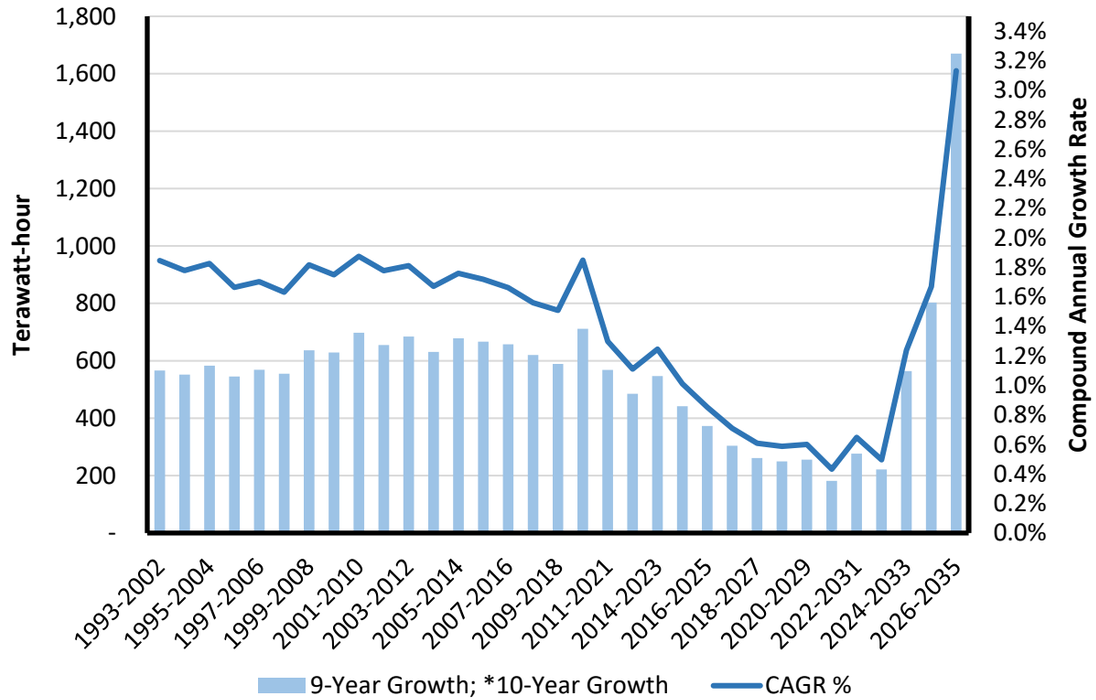


Figure 9: Net Energy for Load Growth and Rate Projections

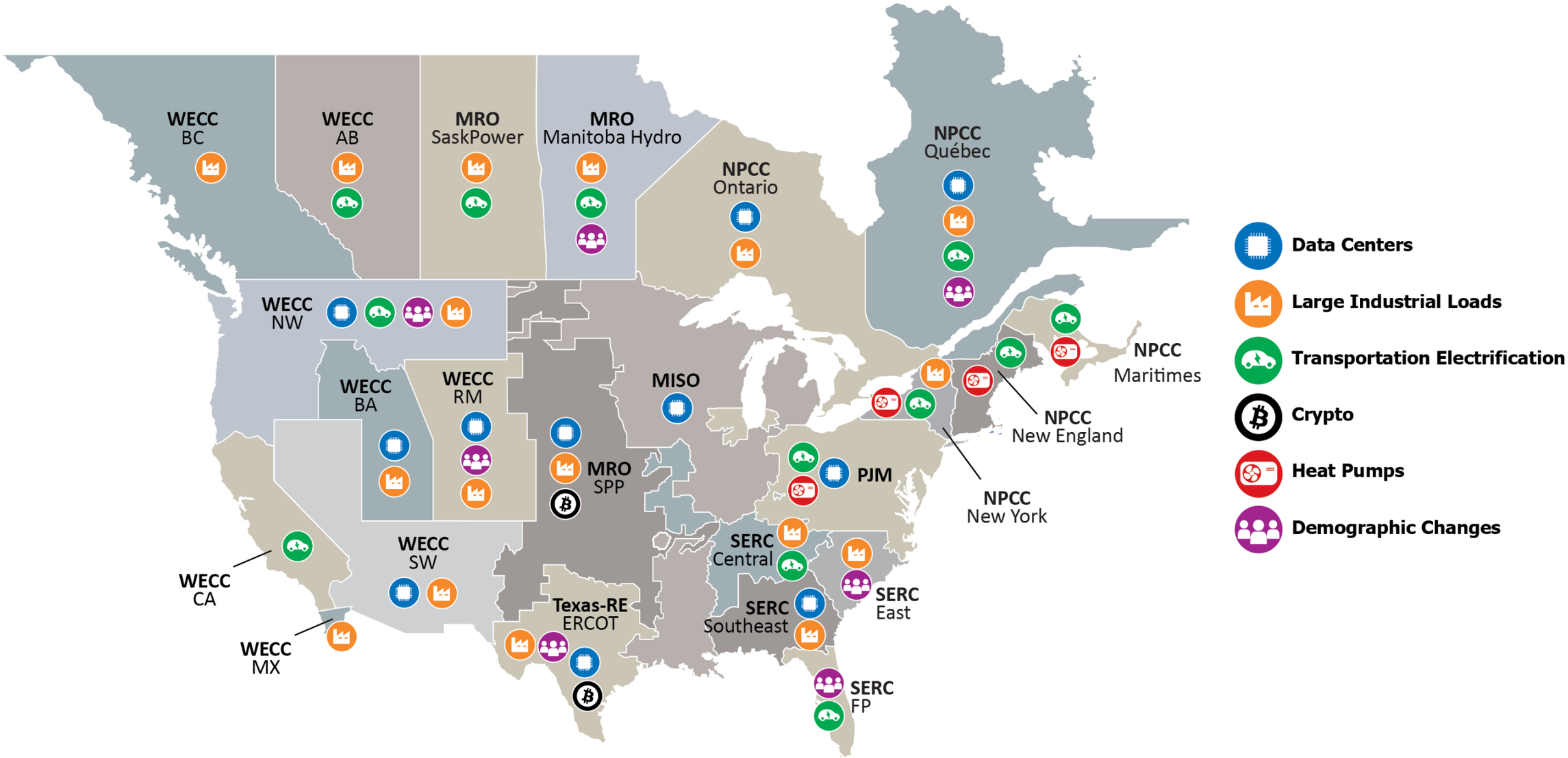


Figure 10: Primary Demand Drivers by Assessment Area

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.

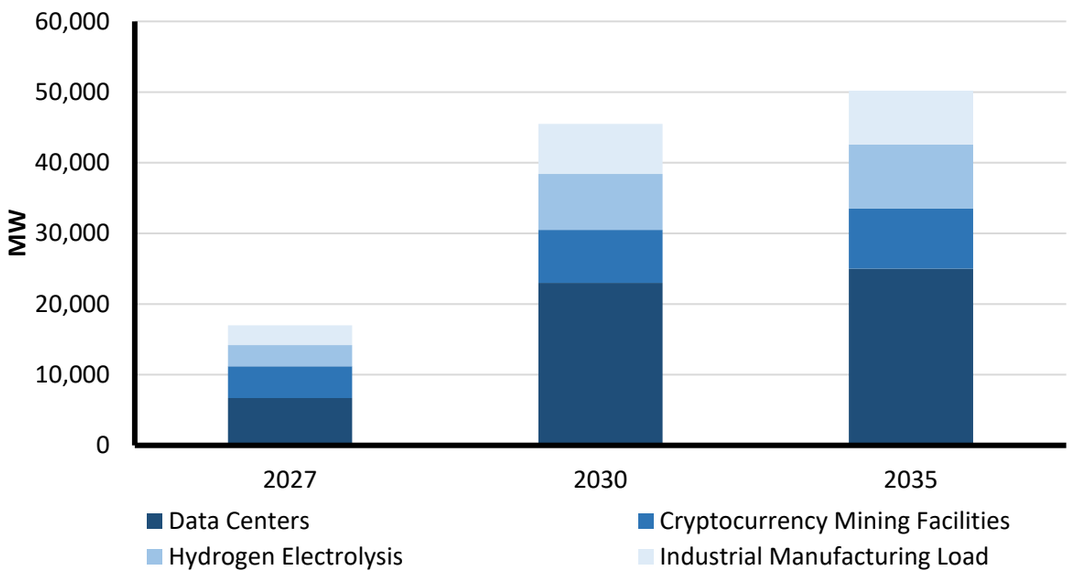


Figure 11: Large-Load Projection Breakdown in ERCOT

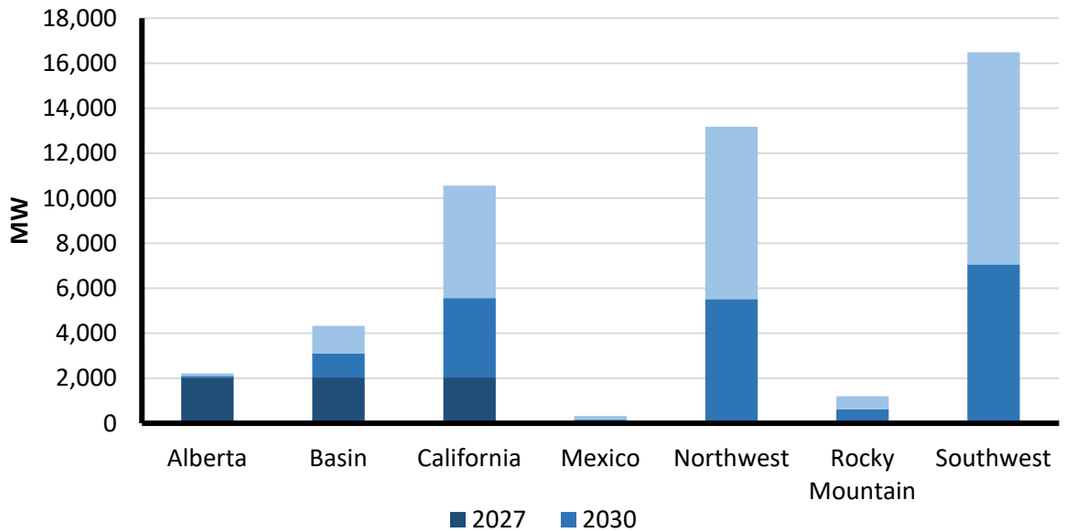


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

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.

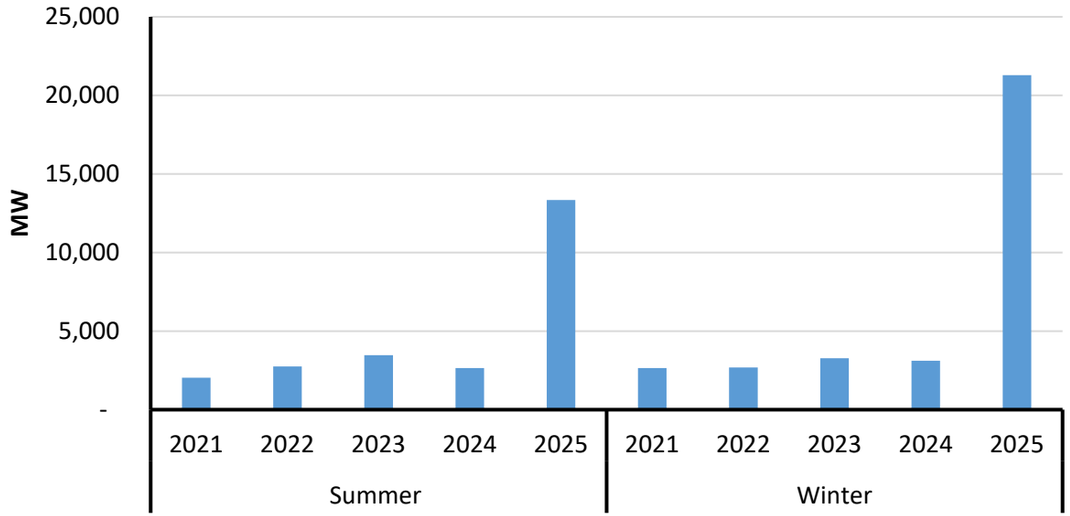


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

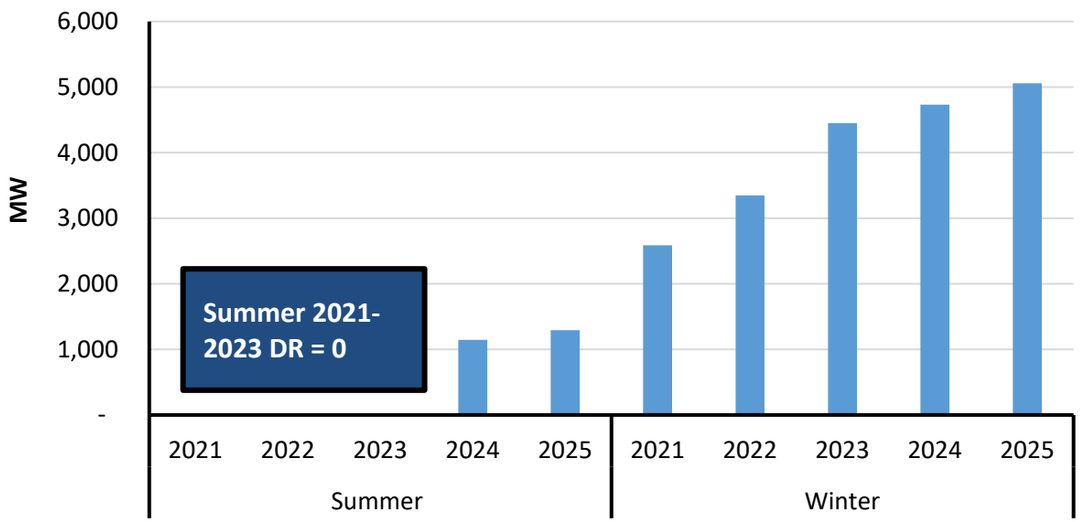


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

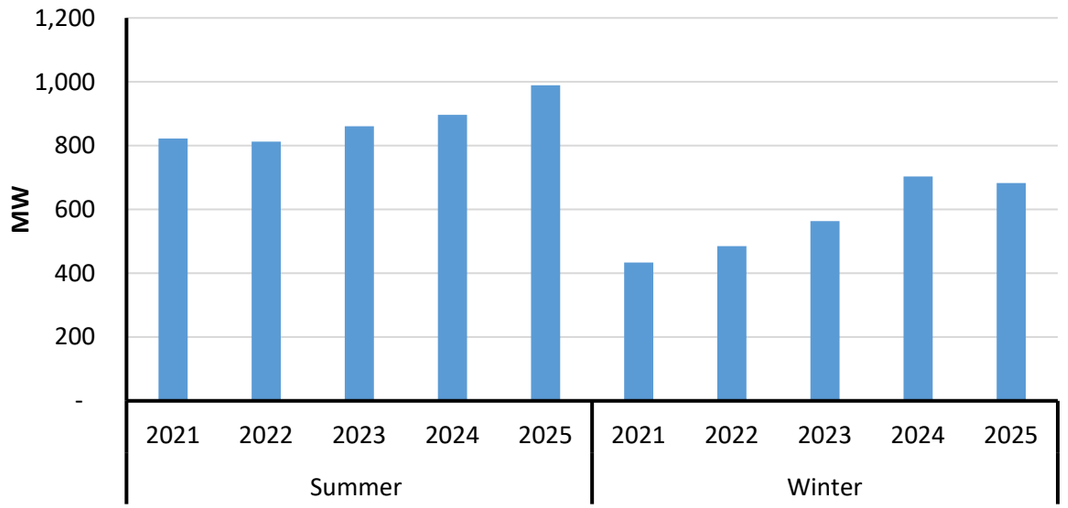


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

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.

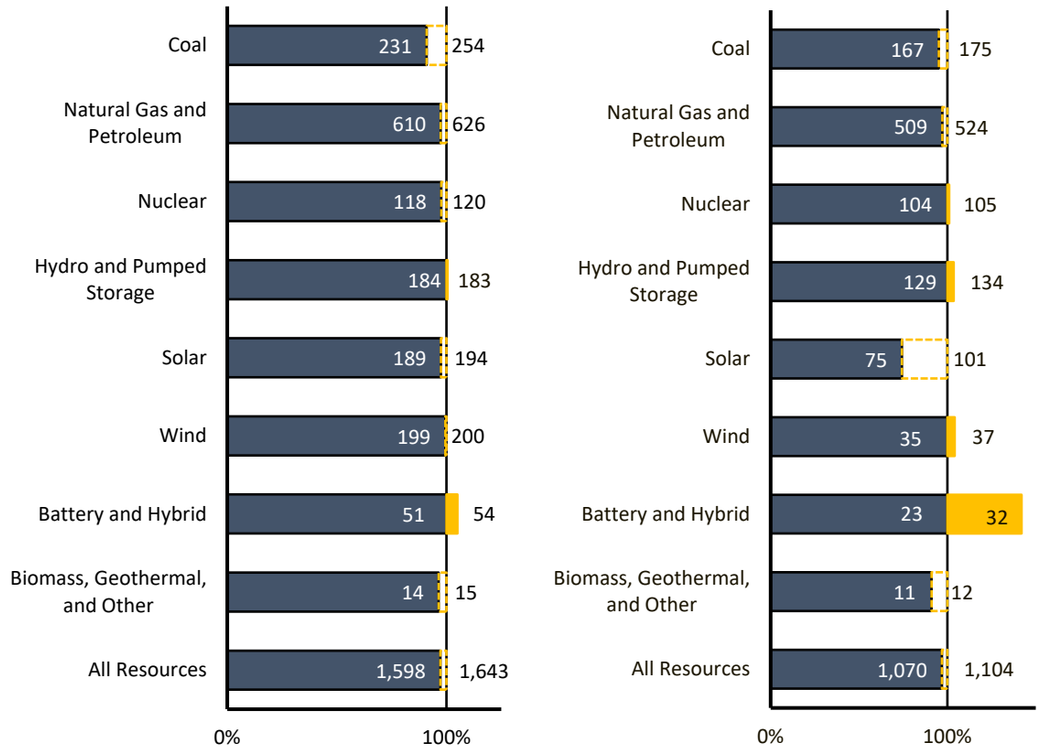


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections

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.

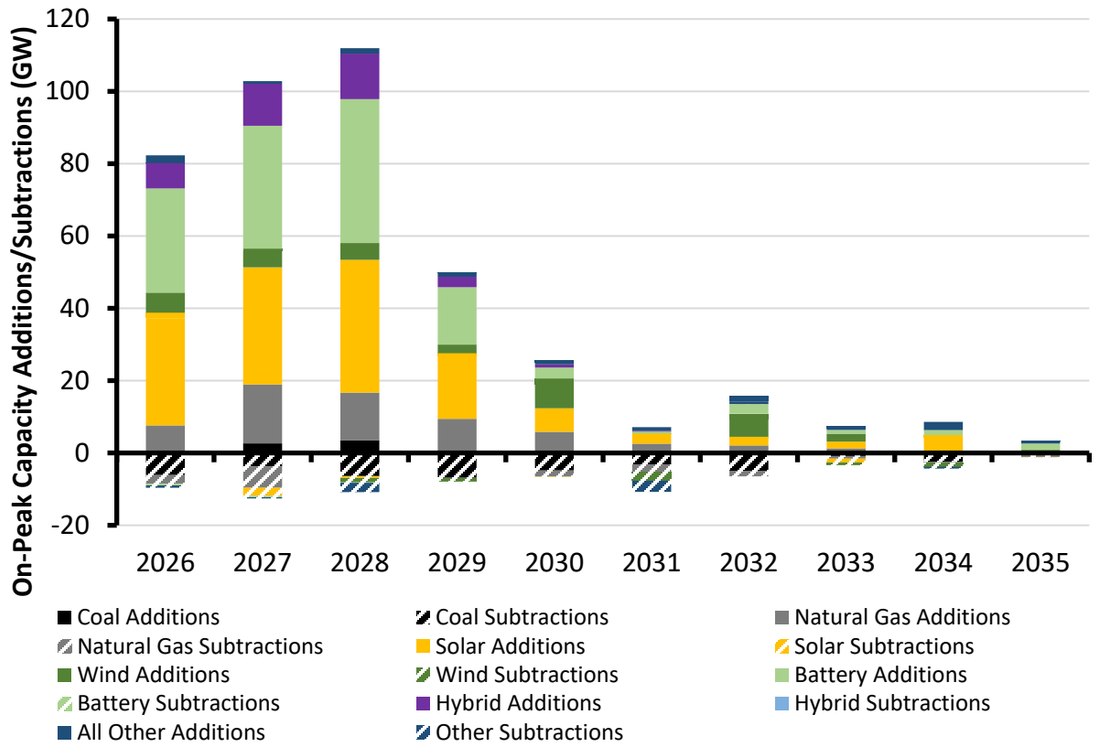


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

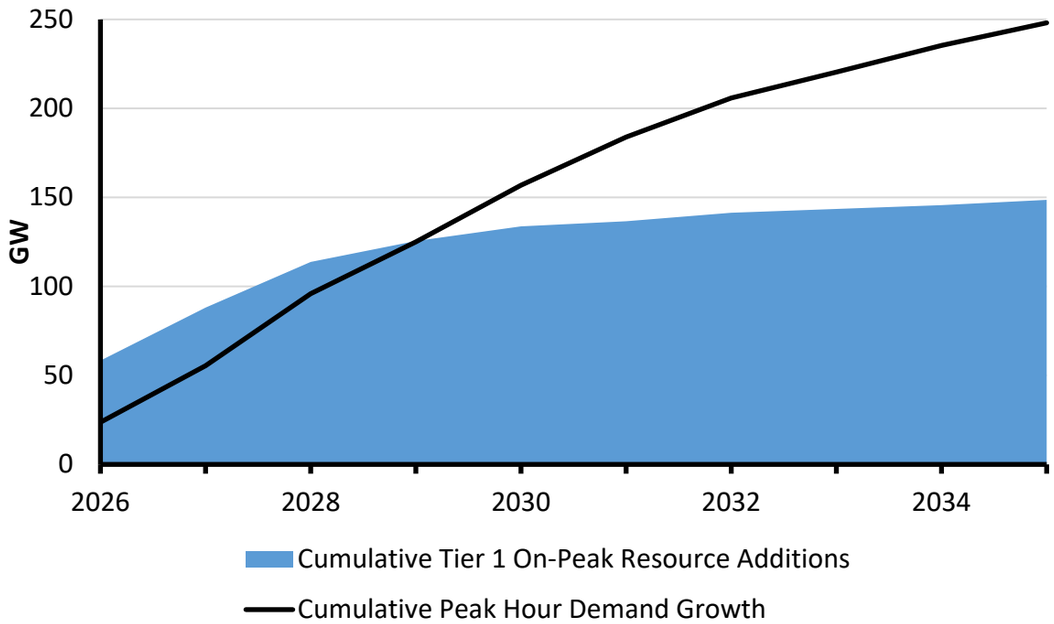


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

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.

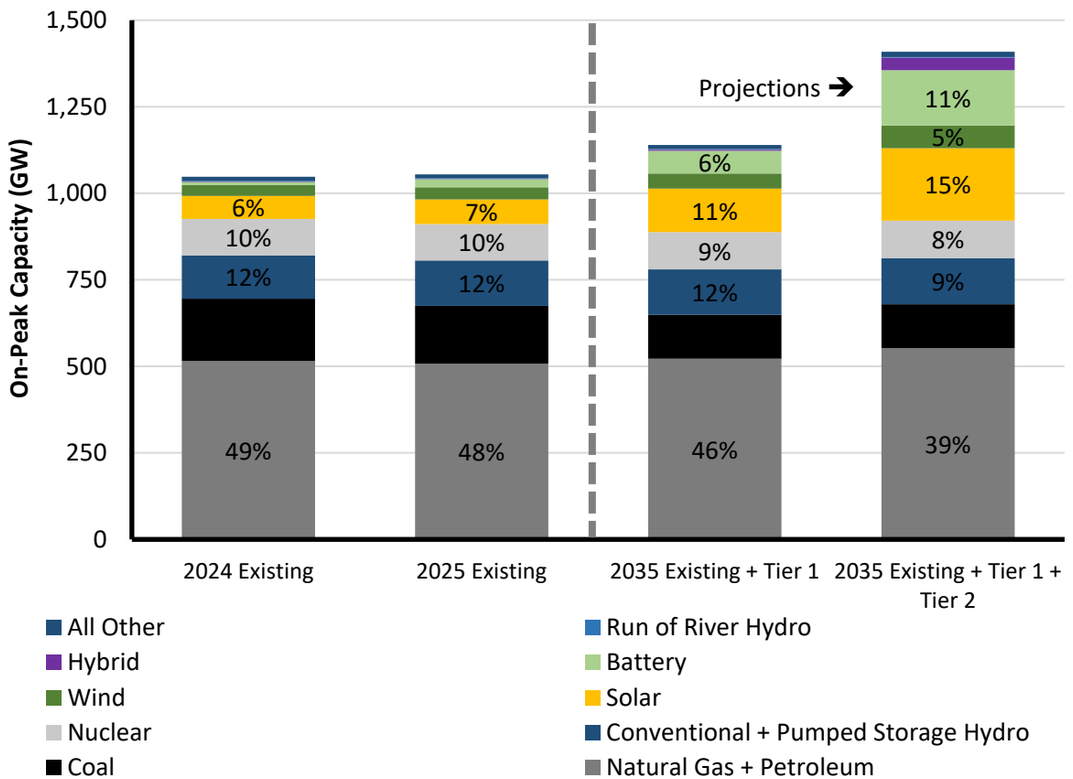


Figure 19: North America On-Peak Capacity Shares by Resource Type

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.

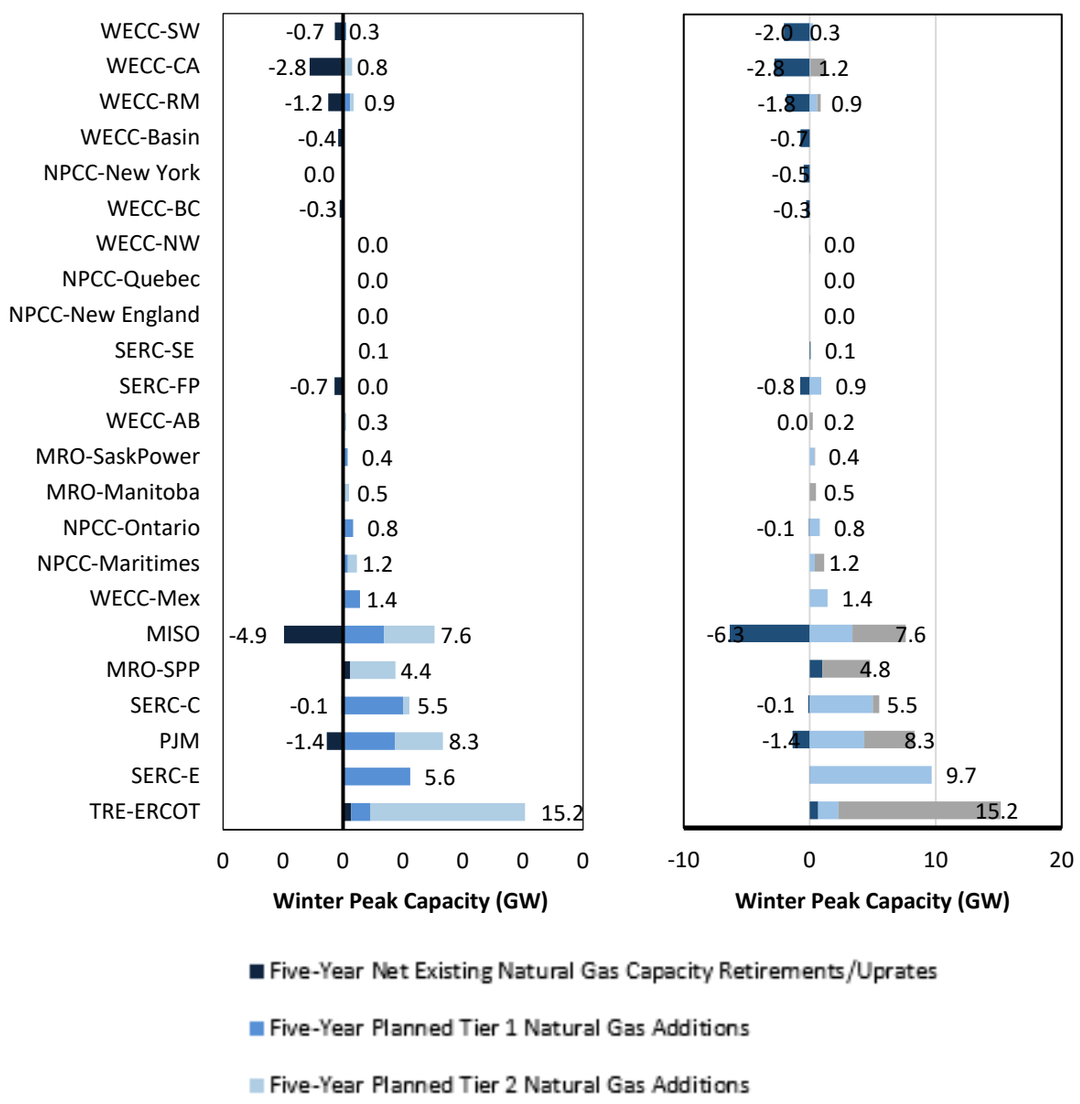


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

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.

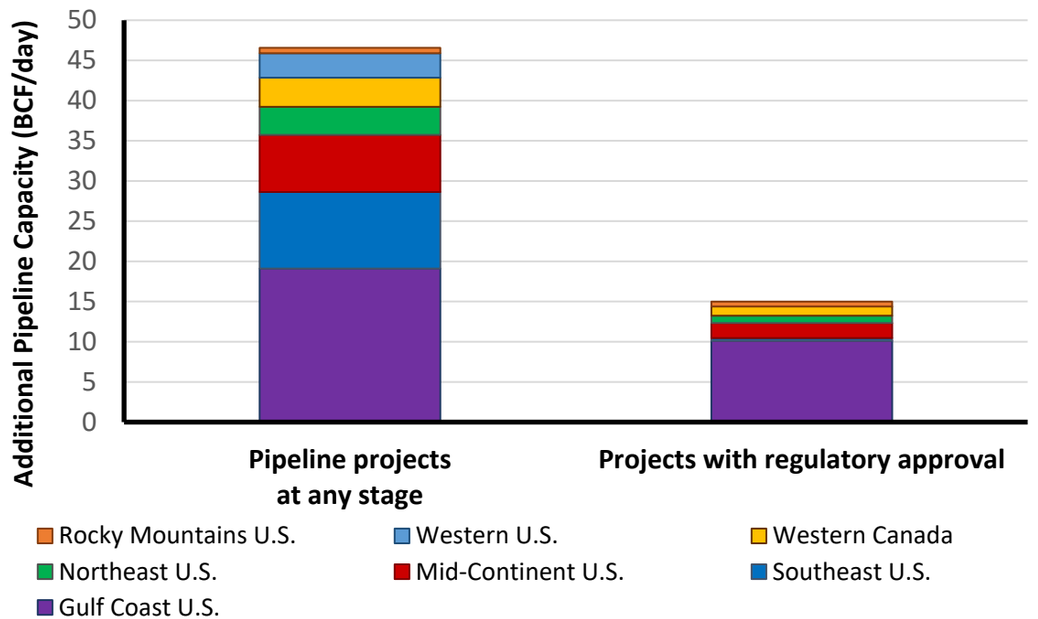


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

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.

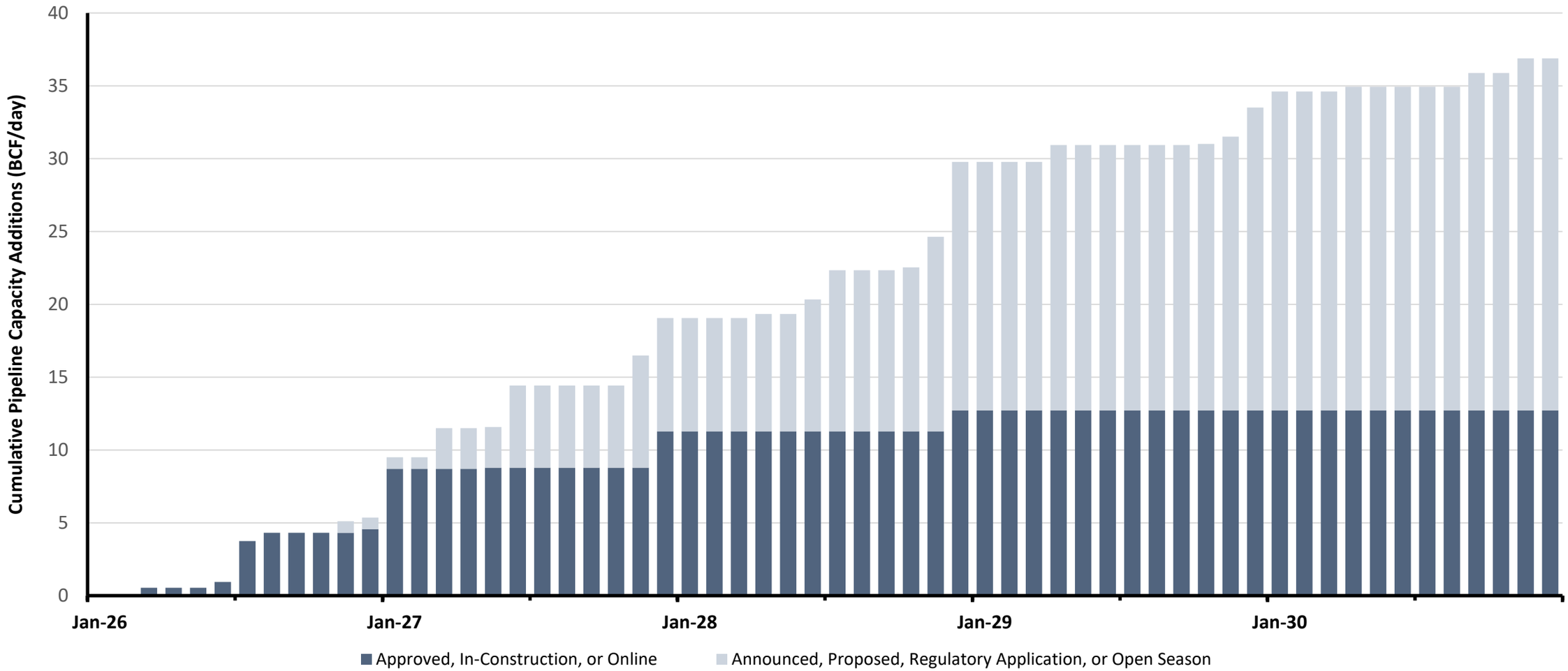


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

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.

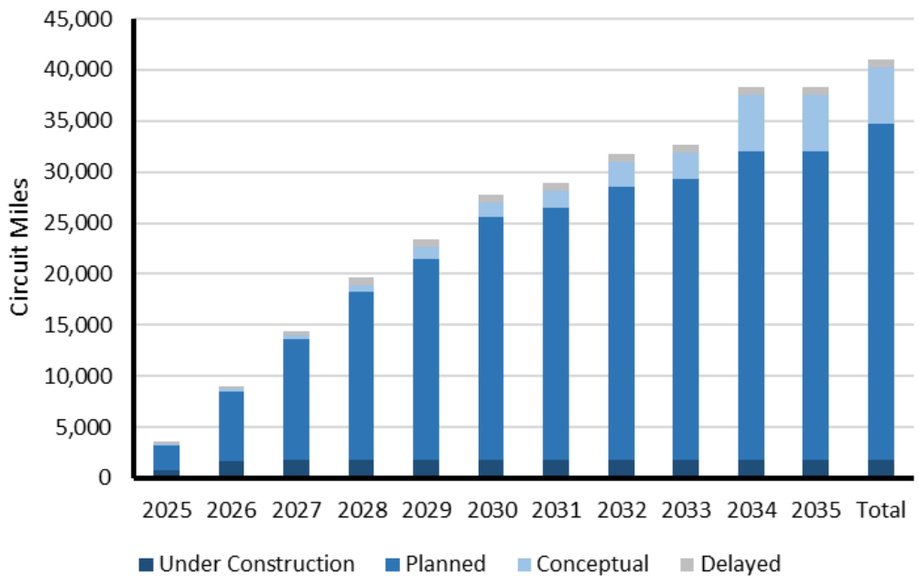


Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]

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.

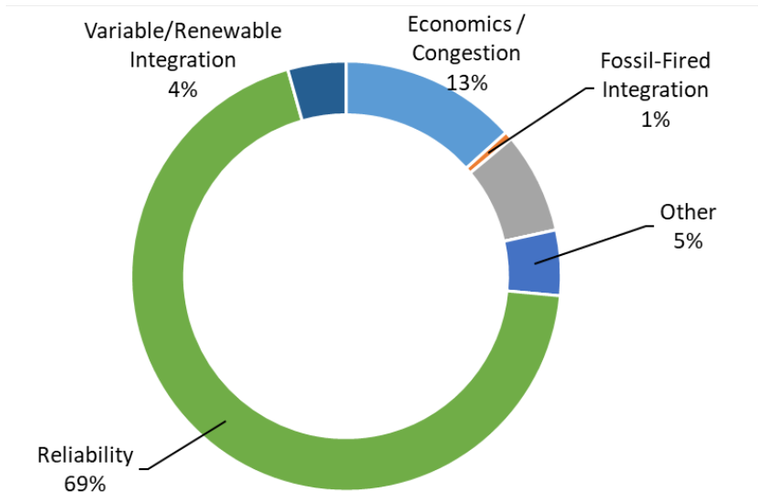


Figure 24: Future Transmission Circuit Miles by Primary Driver

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.

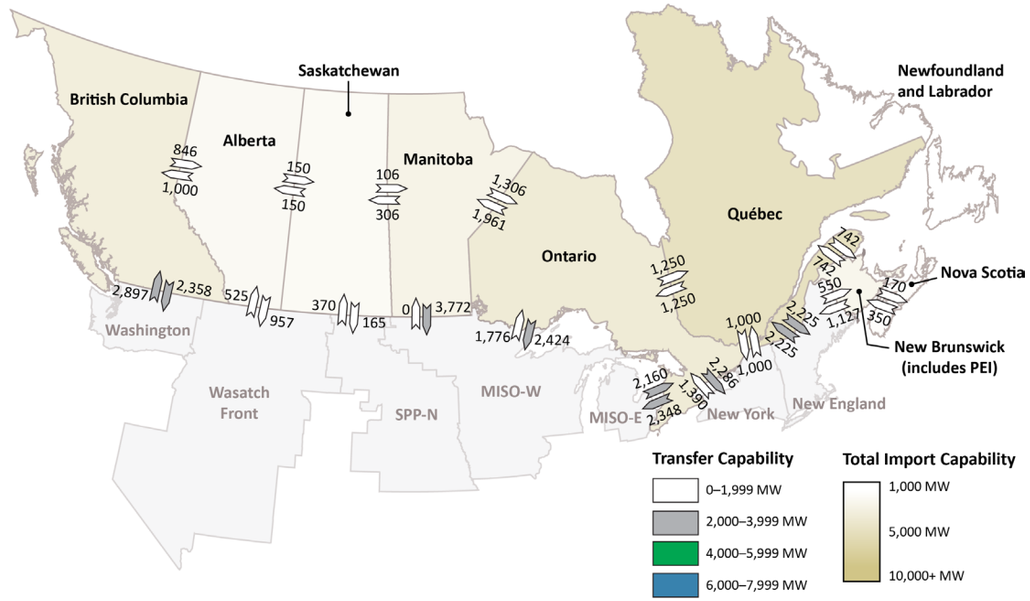


Figure 25: Transfer Capabilities (Summer)

[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.

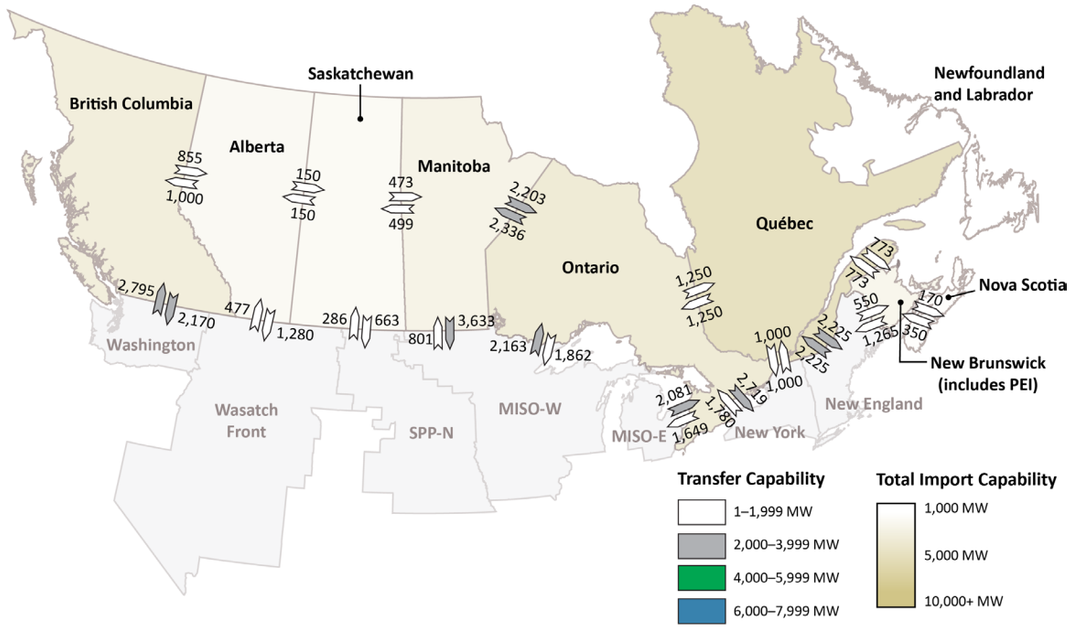


Figure 26: Transfer Capabilities (Winter)

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

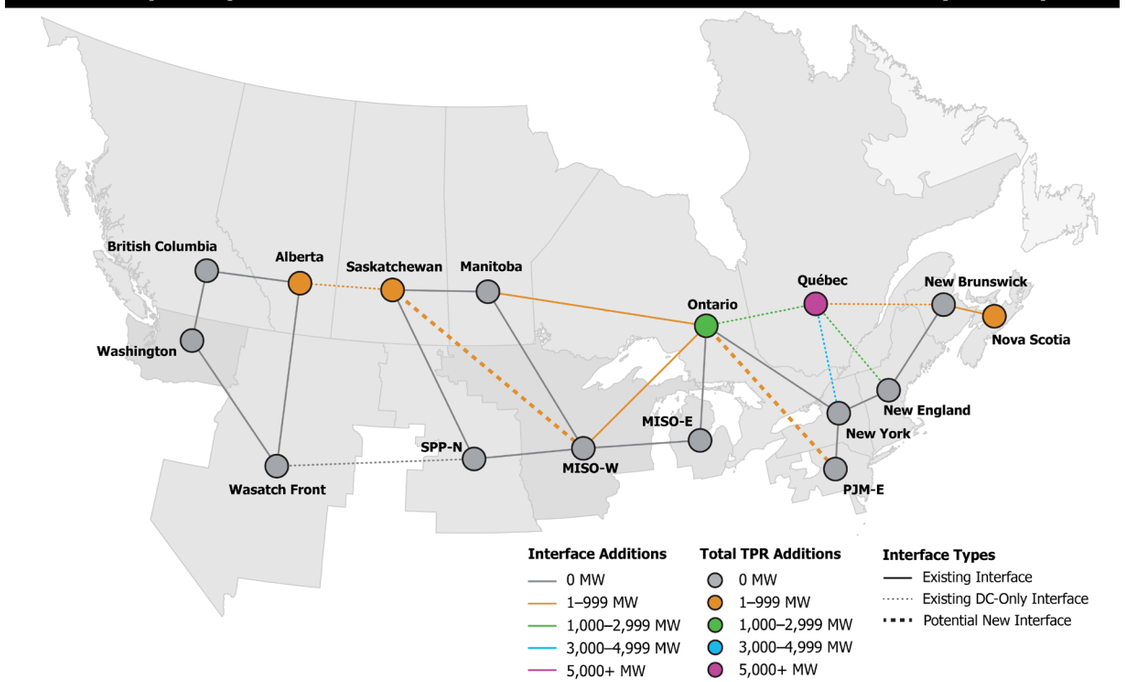
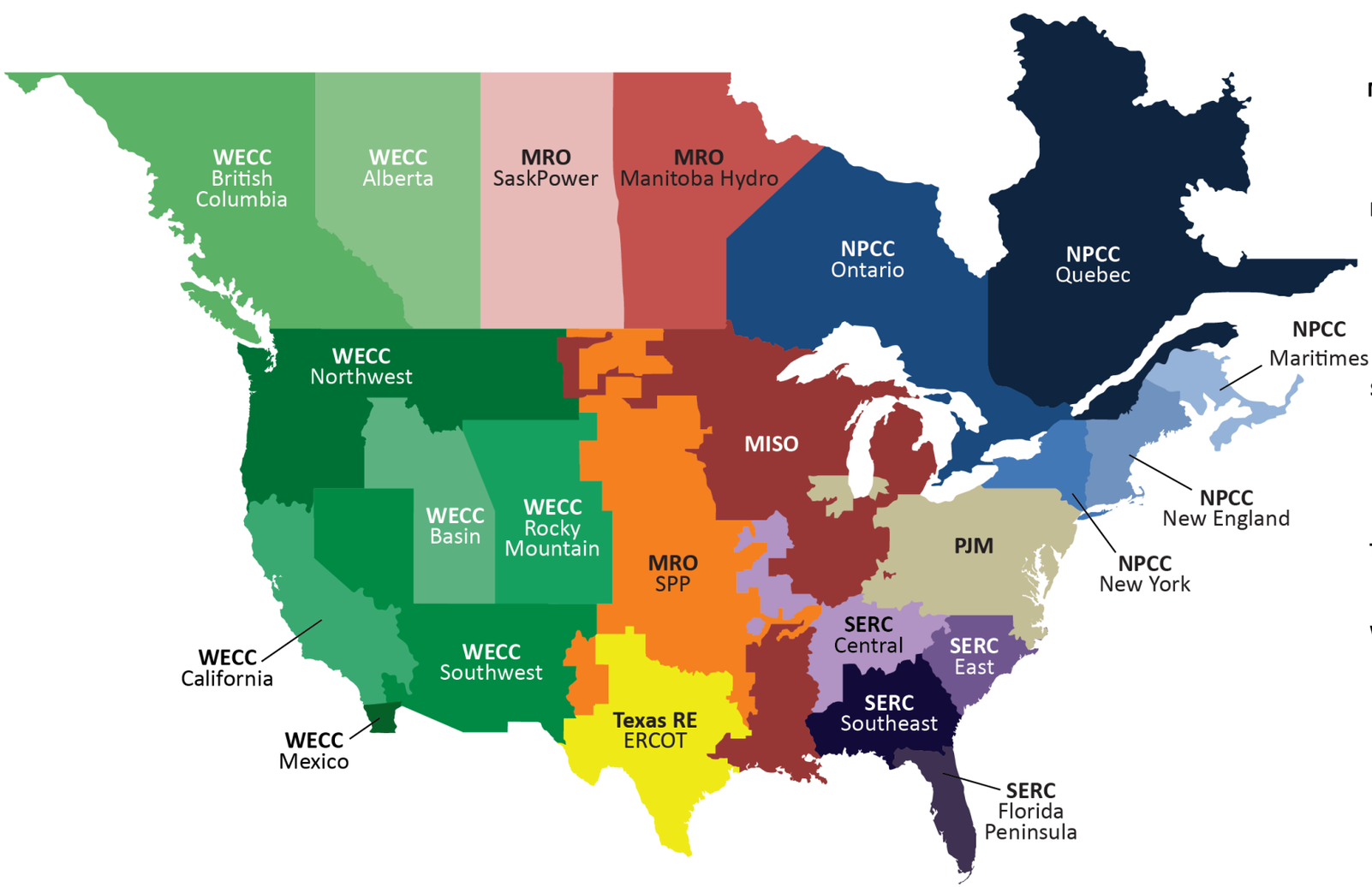


Figure 27: Transfer Capability Additions

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 *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP *(Southwest Power Pool)*

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Florida Peninsula
- SERC-Southeast

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC – Western Electricity Coordinating Council
- WECC-Alberta
- WECC-Basin
- WECC-British Columbia
- WECC-California
- WECC-Mexico
- WECC-Northwest
- WECC-Rocky Mountain
- WECC-Southwest

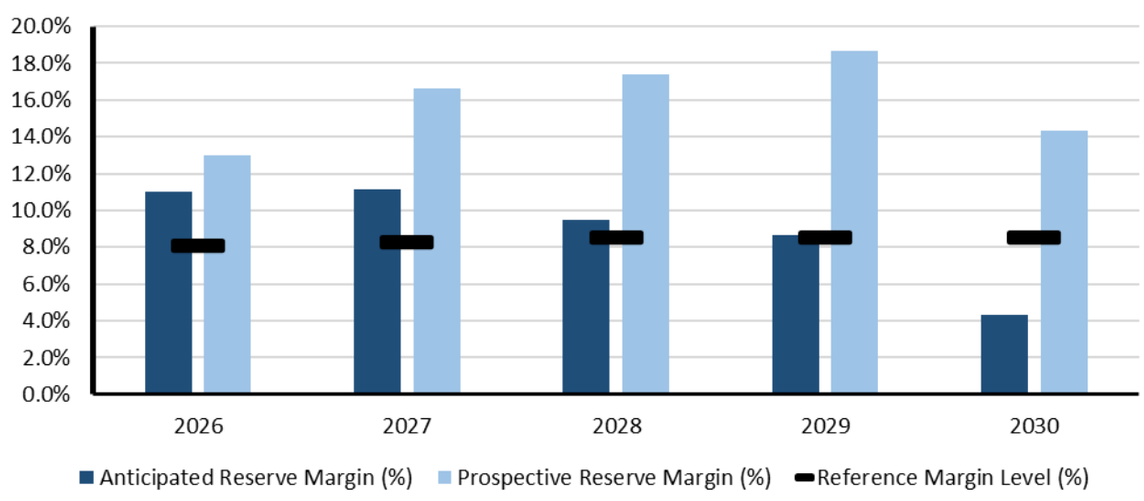


MISO

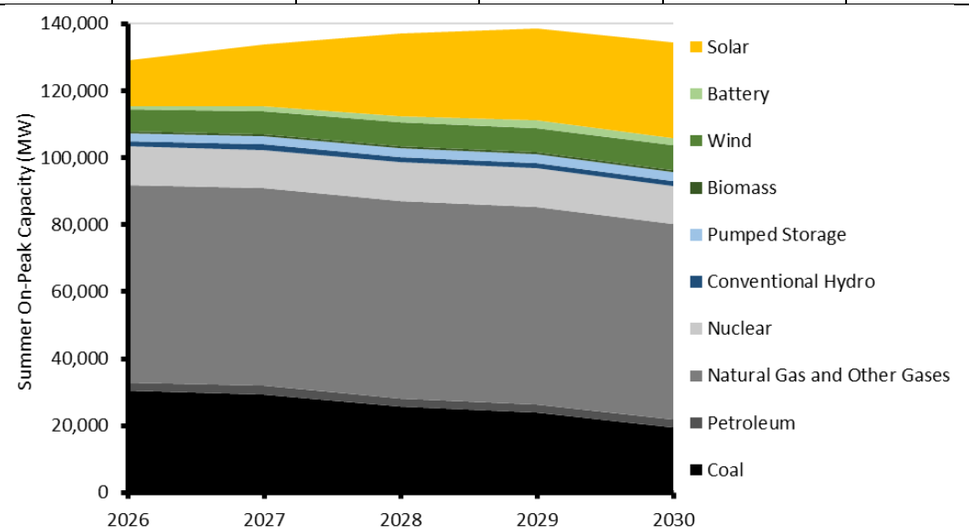
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery 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.

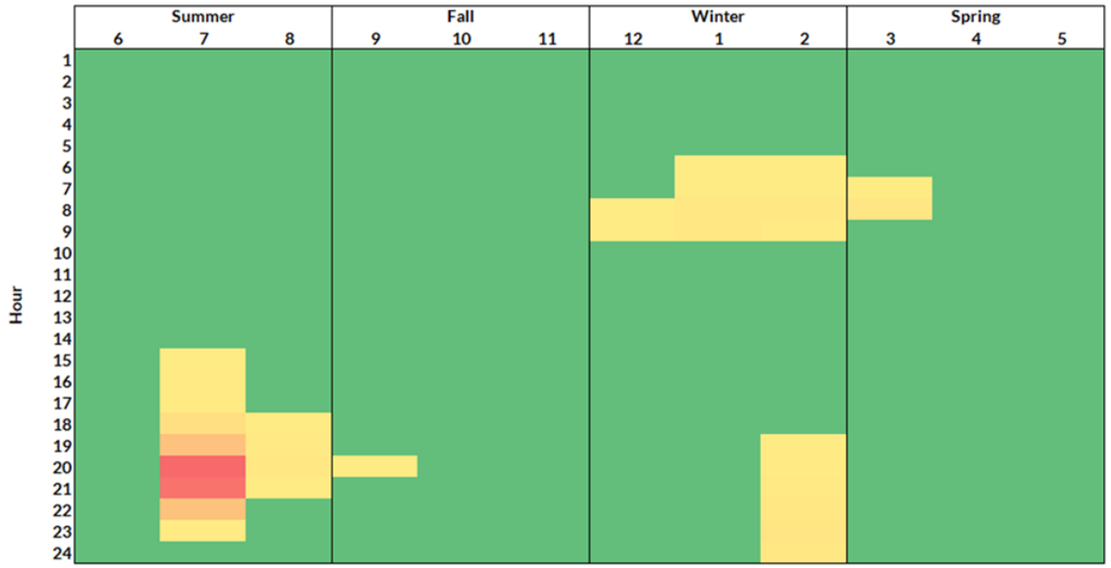
Base-Case Summary of Results

	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

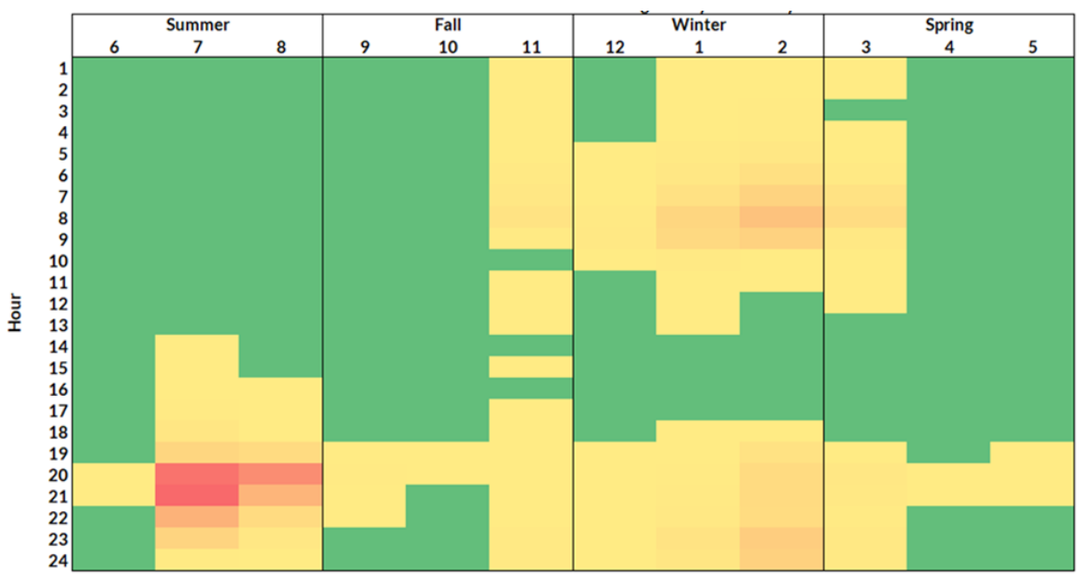
*Provides the 2024 ProbA Results for Comparison

**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.

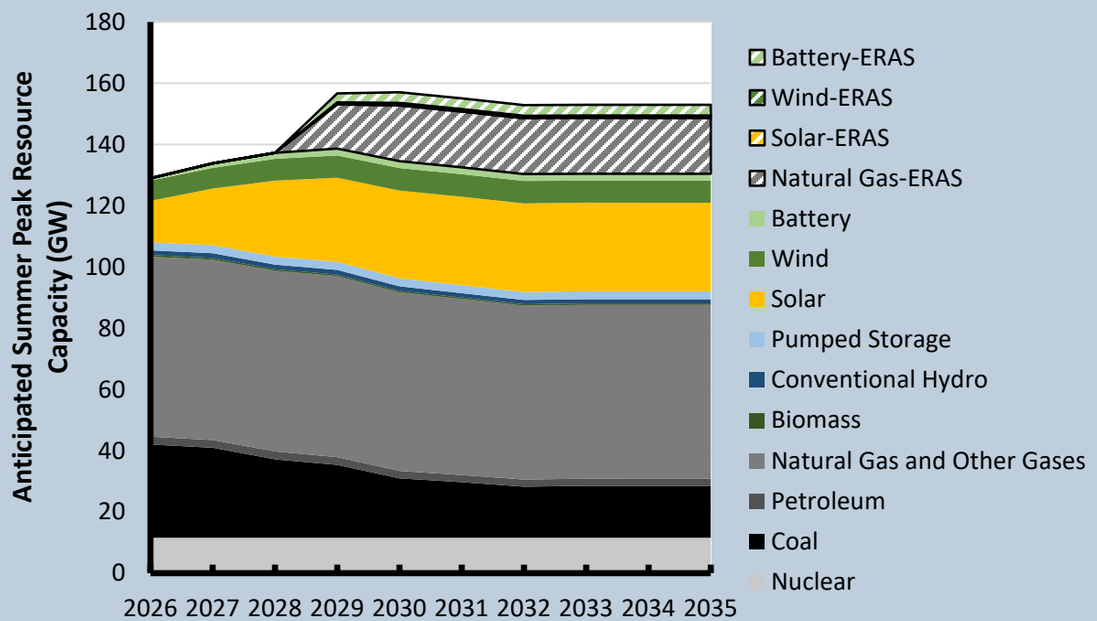
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited 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.

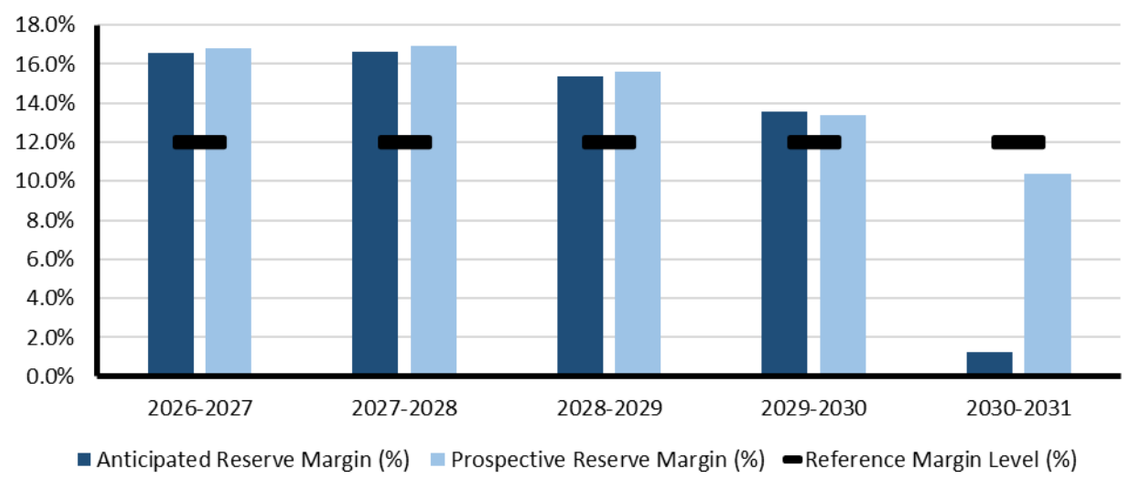


MRO-Manitoba Hydro

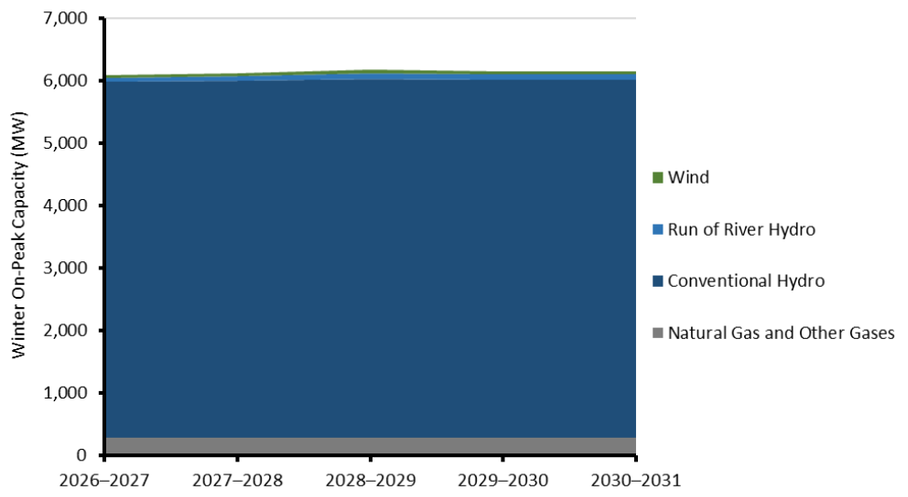
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in 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.

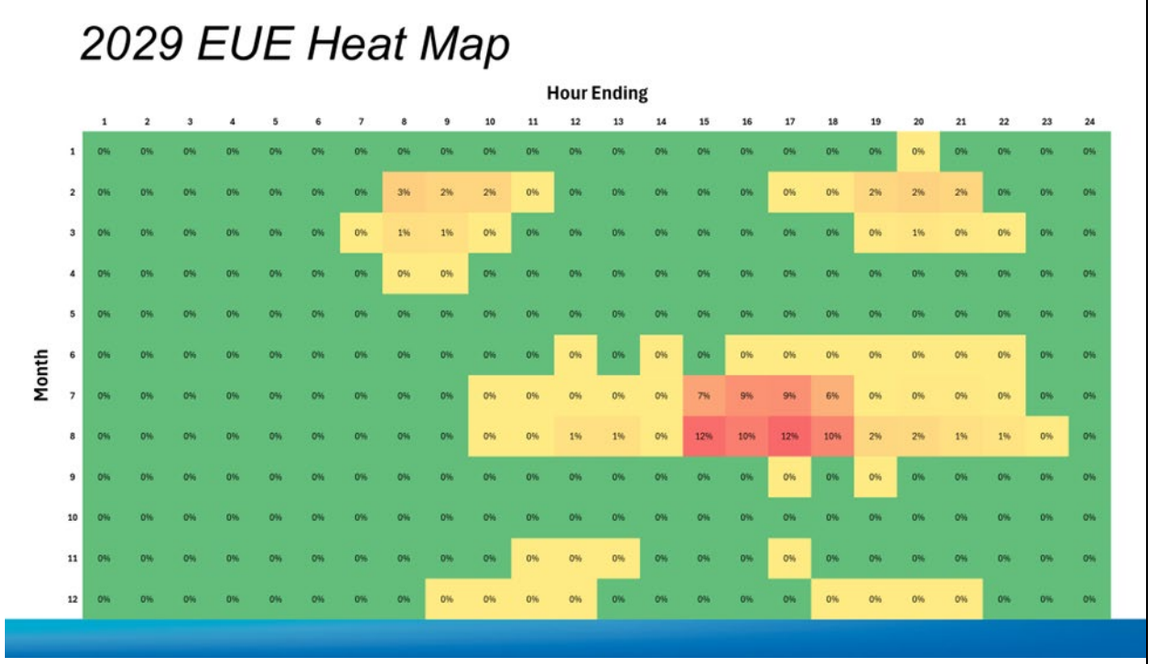
Energy Risk
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific 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.

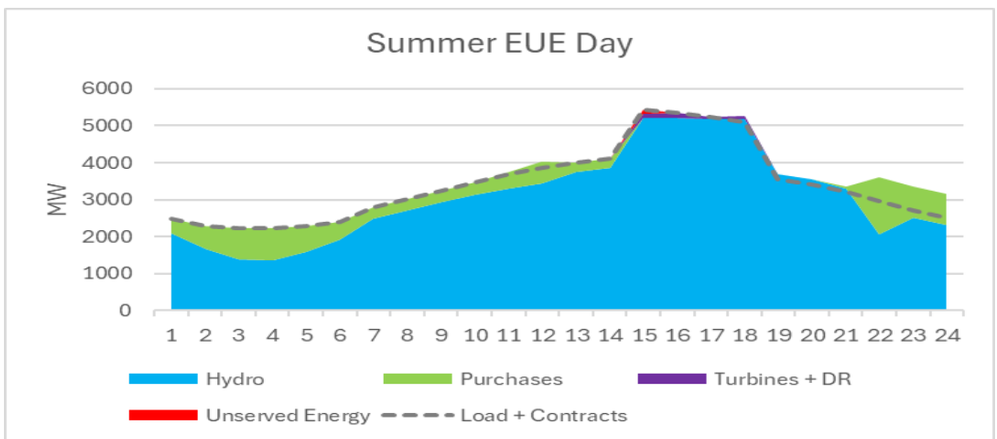
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

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.

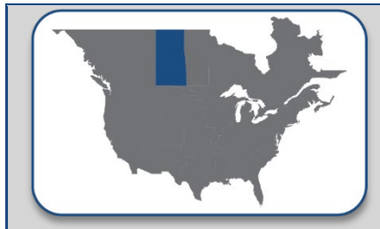
Energy Transfers

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.

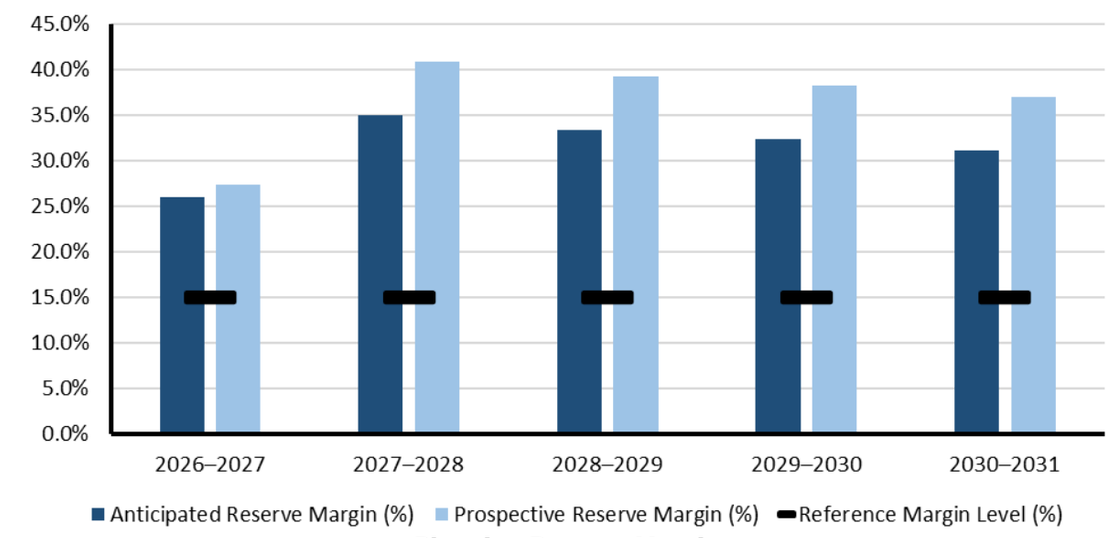


MRO-SaskPower

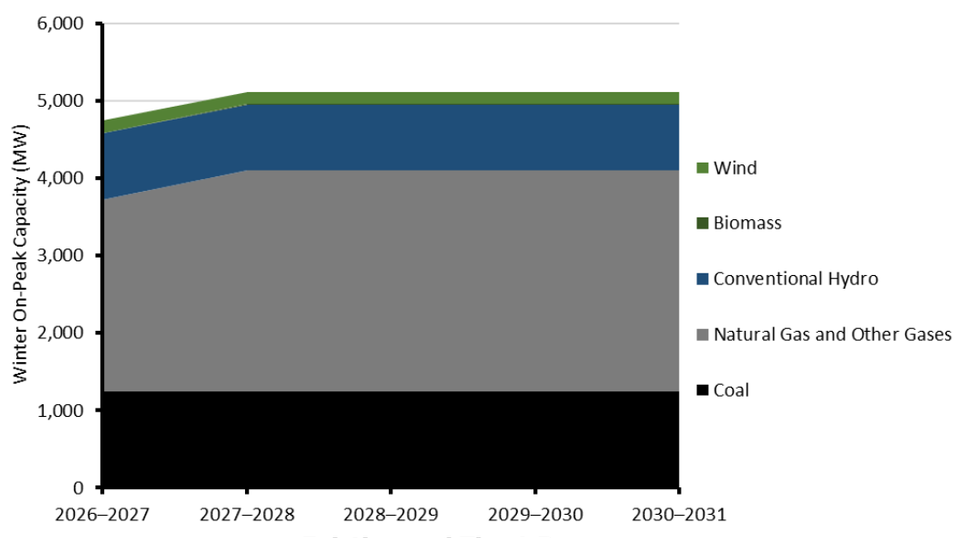
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator 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.

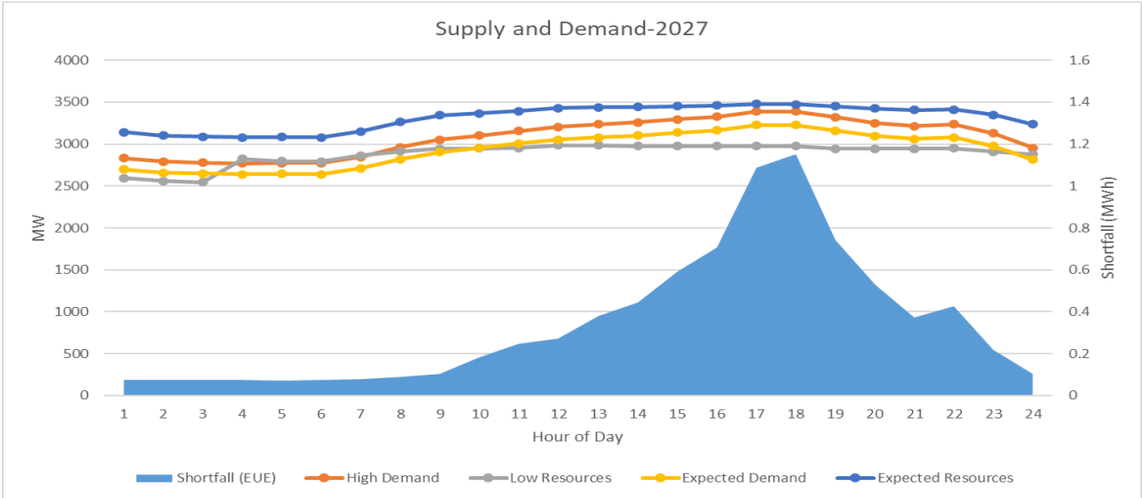
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
*** Provides the 2024 ProbA Results for Comparison**			

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.

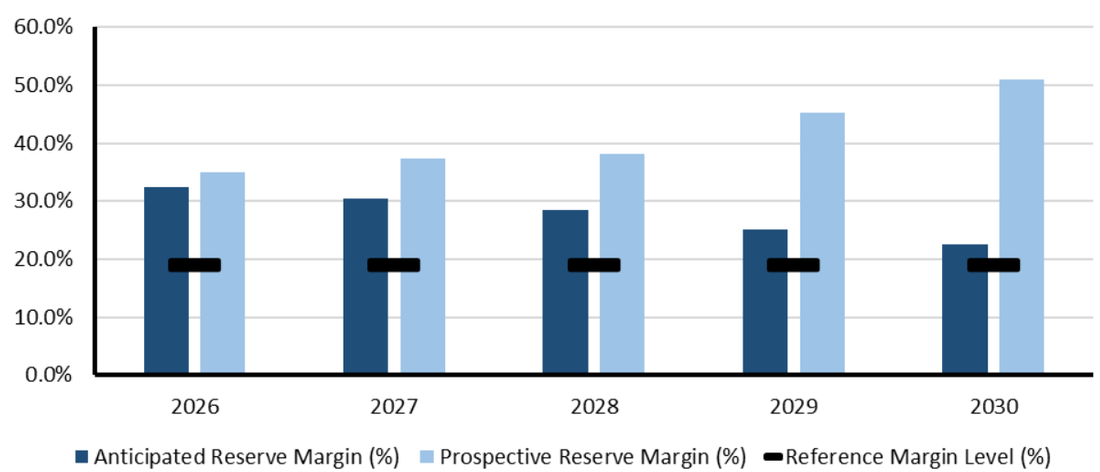


MRO-SPP

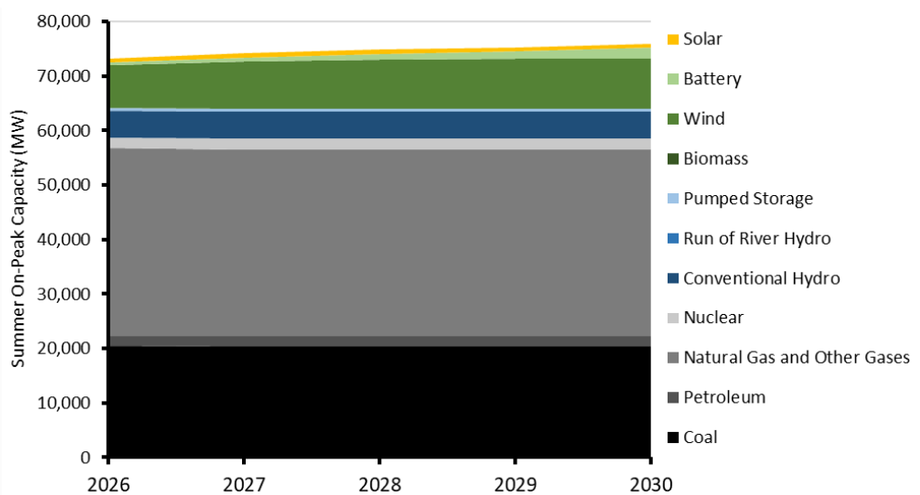
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the 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.					

MRO-SPP Assessment

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.

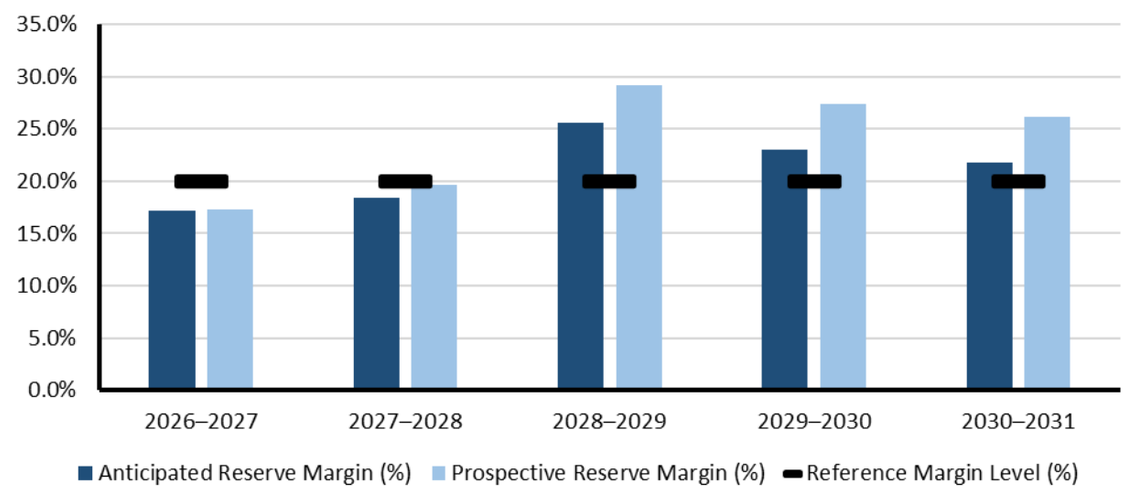


NPCC-Maritimes

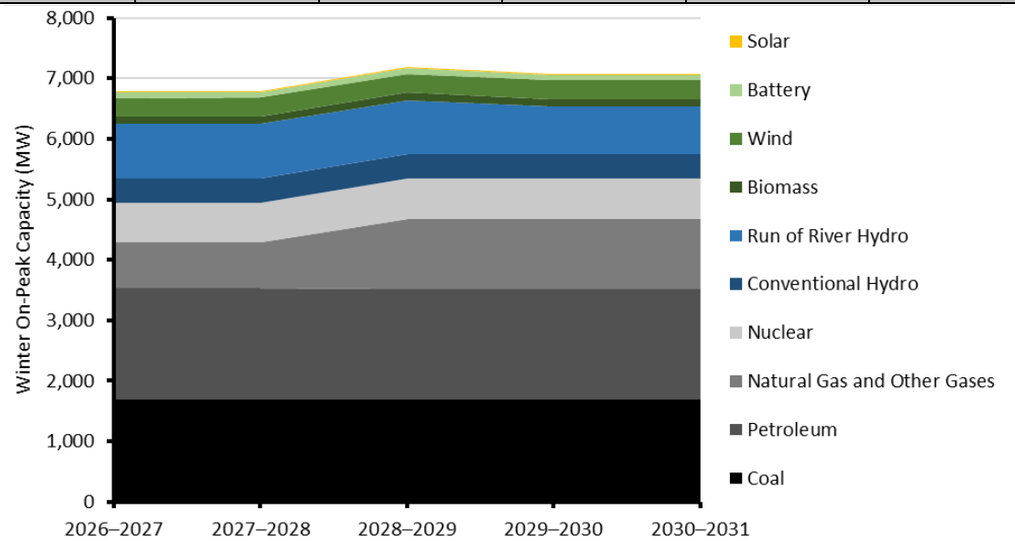
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 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.



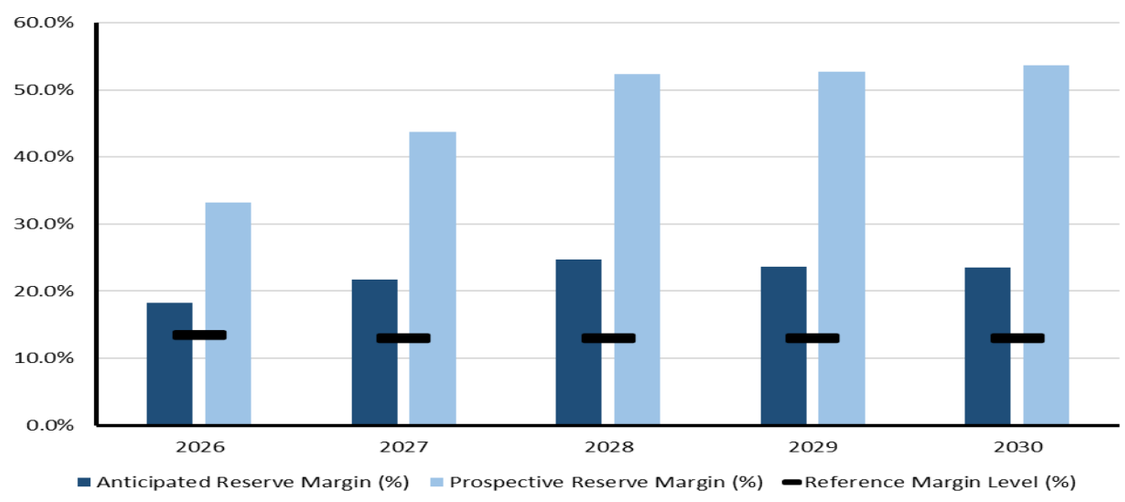
NPCC-New England

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.

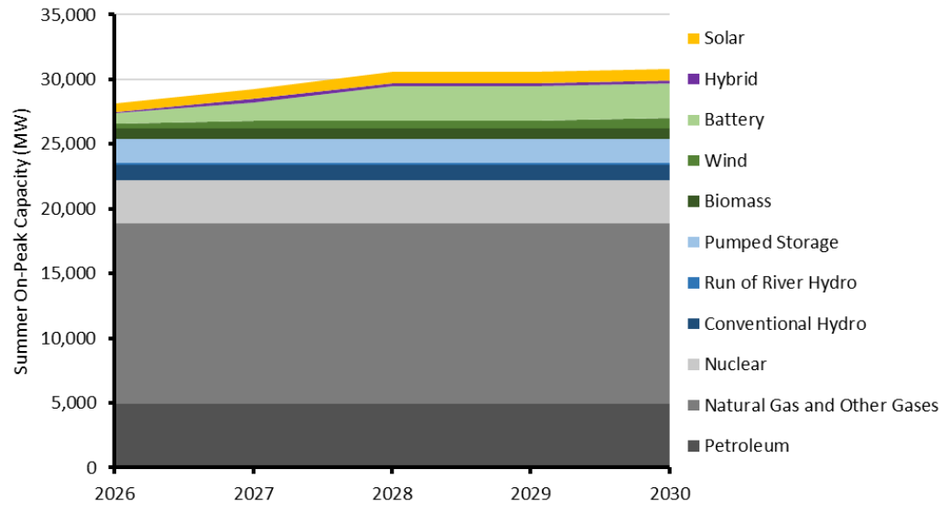
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

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.

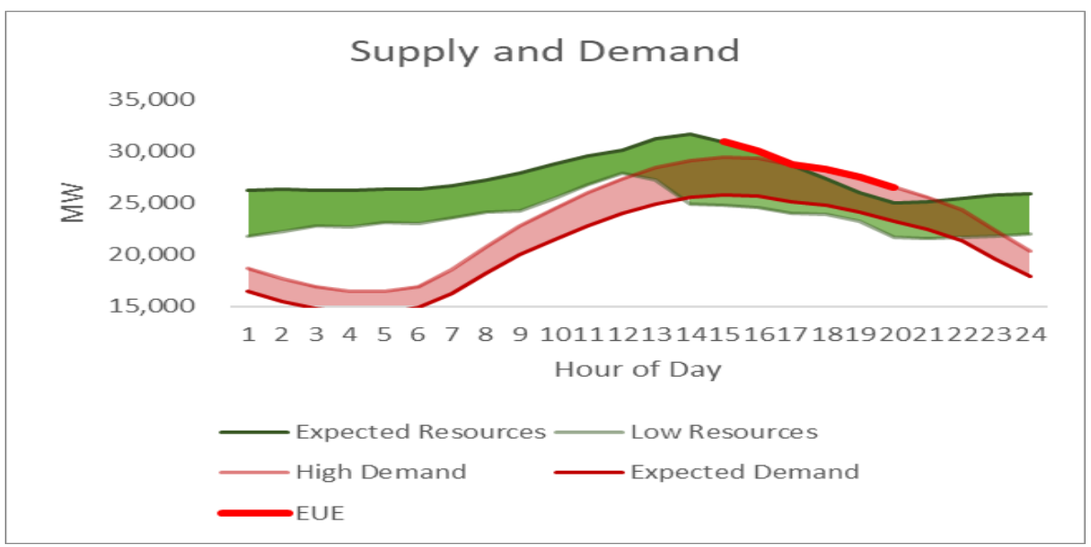
NPCC New England Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

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

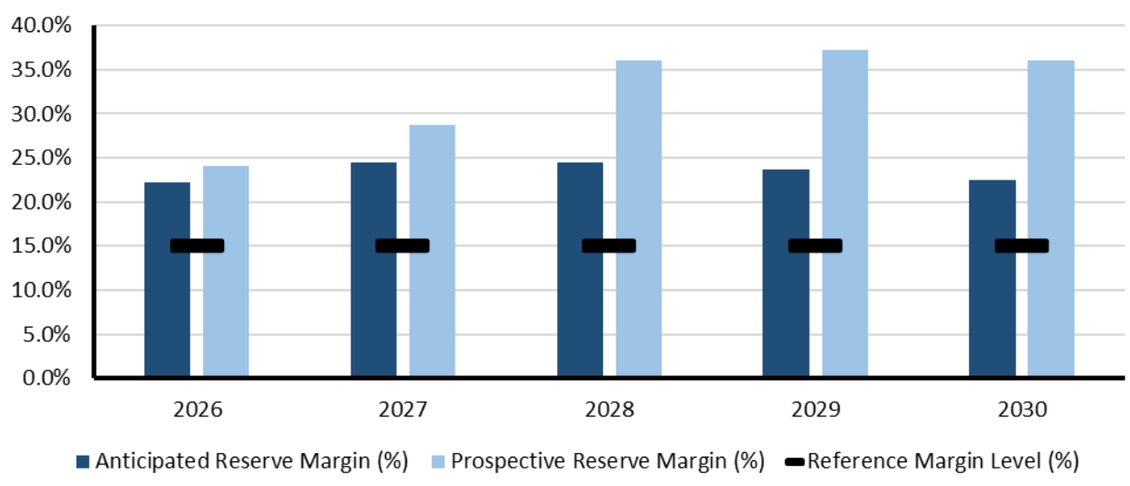


NPCC-New York

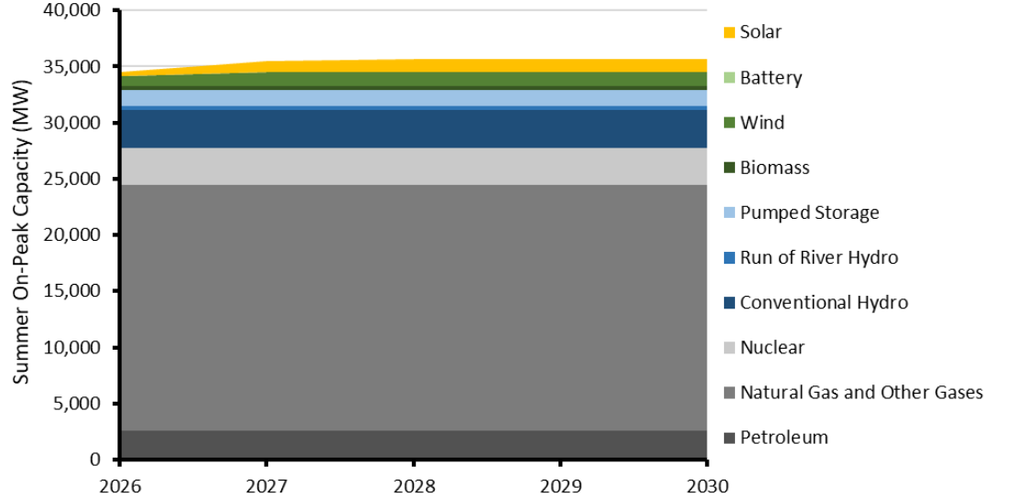
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 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

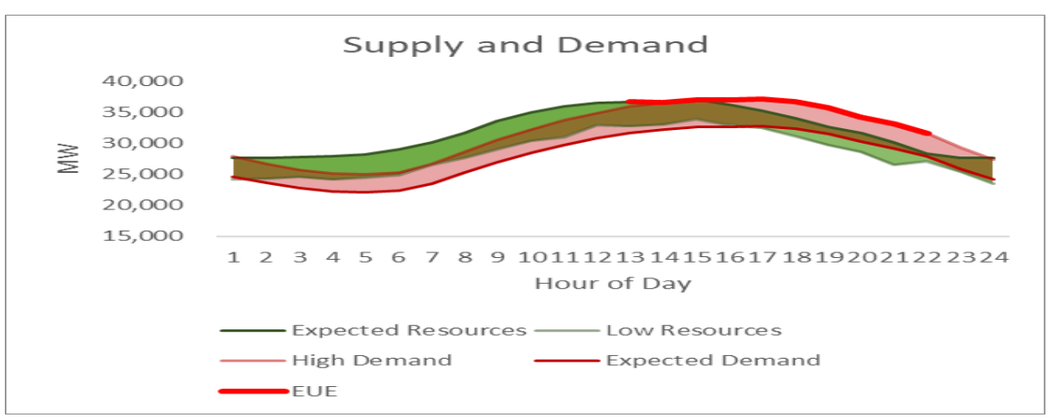
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

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

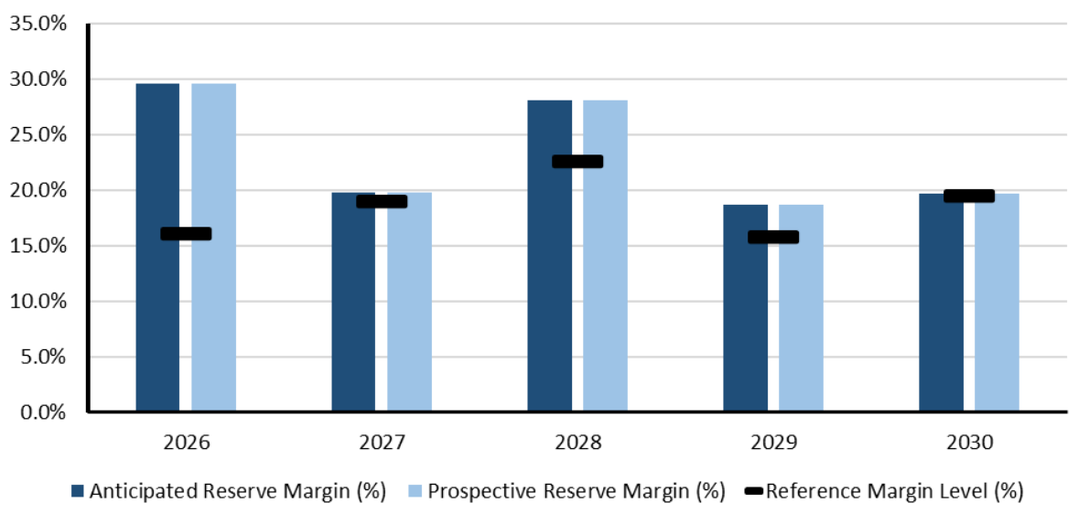


NPCC-Ontario

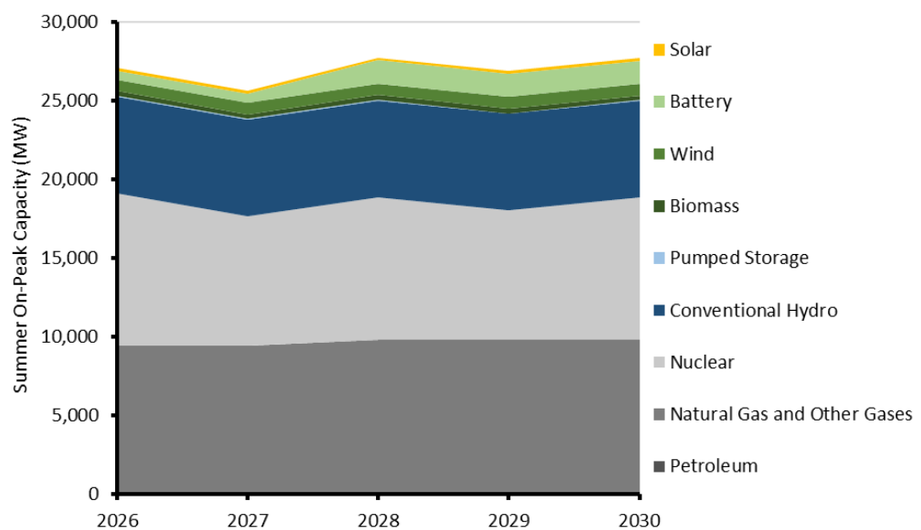
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for 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.

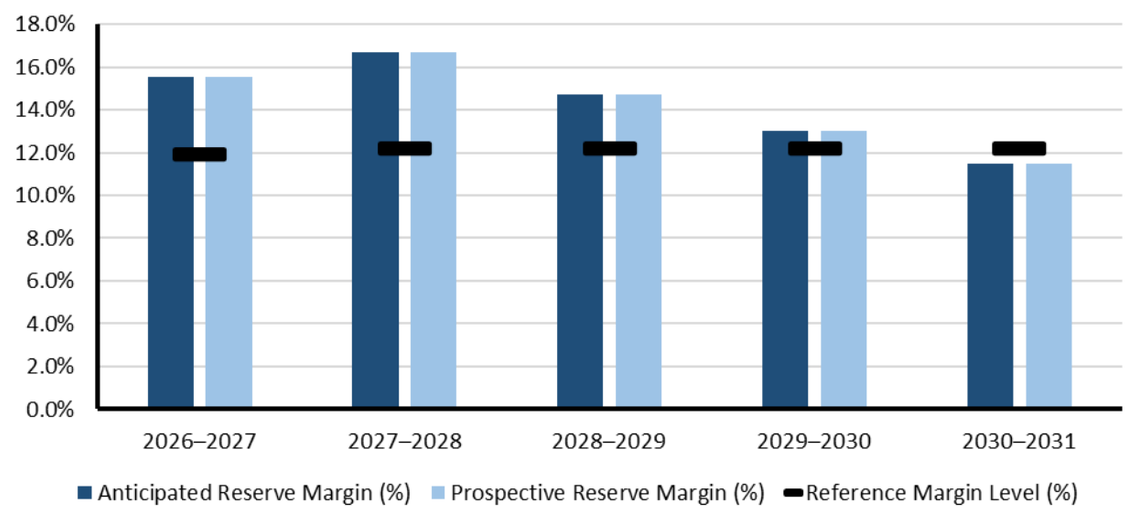


NPCC-Québec

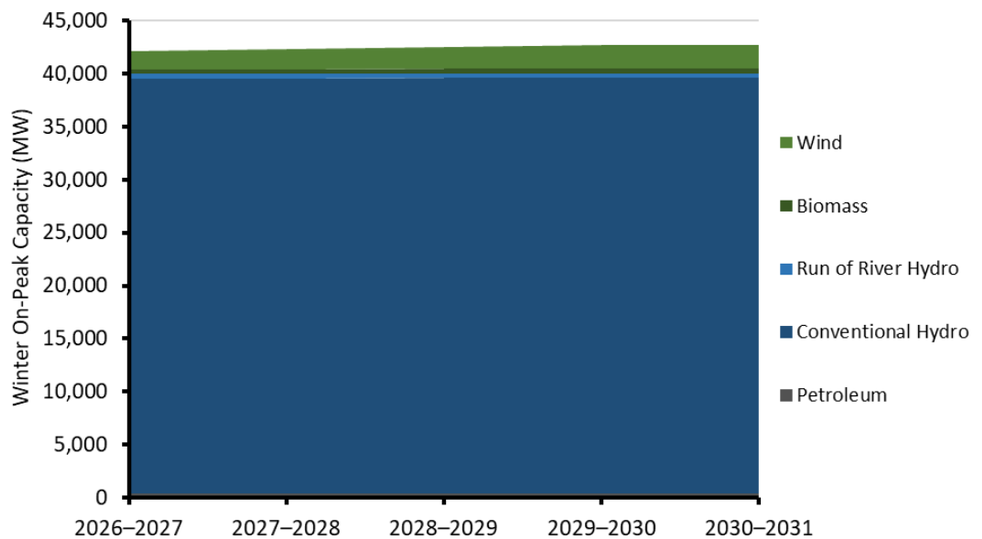
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the 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.

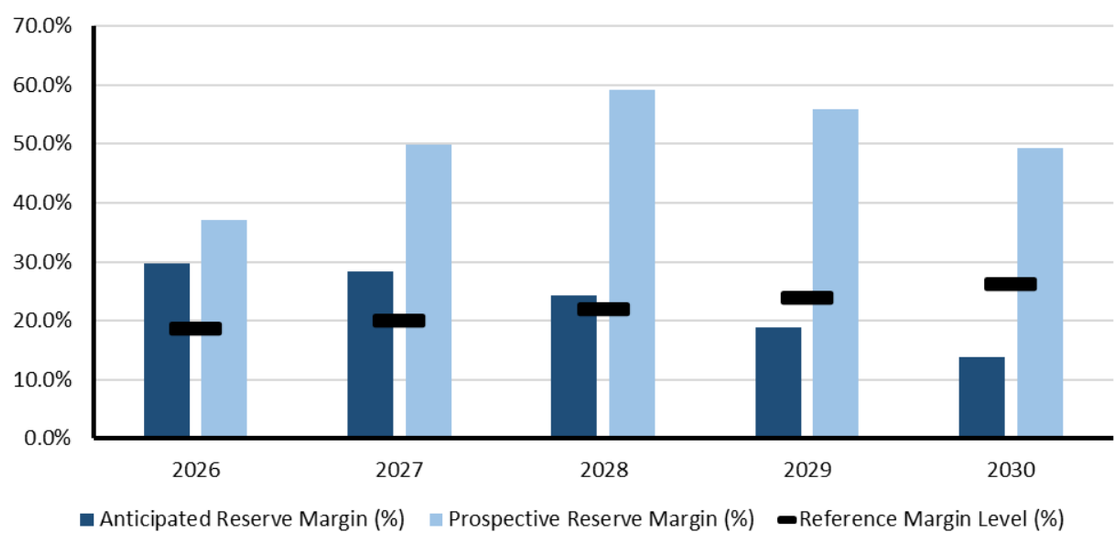


PJM

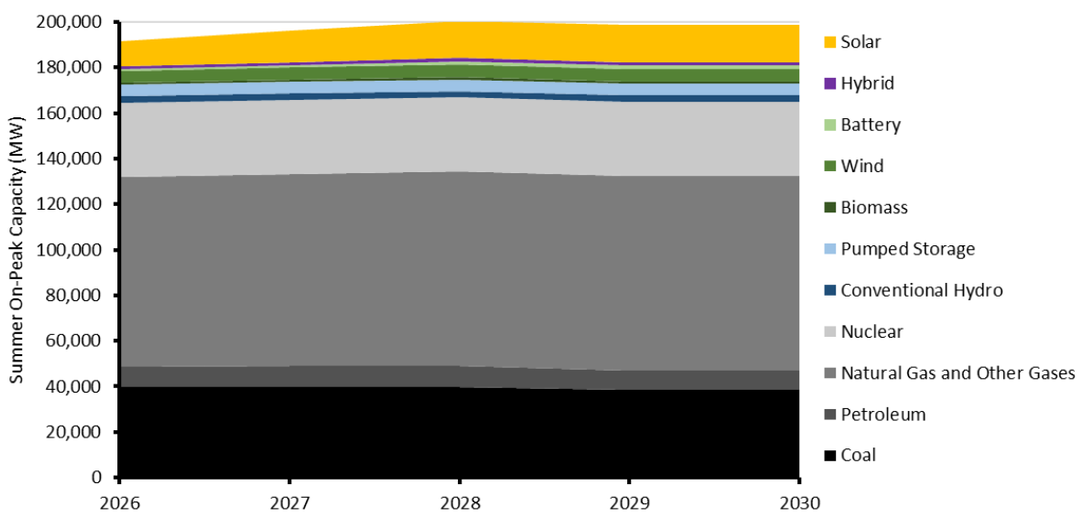
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. 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.

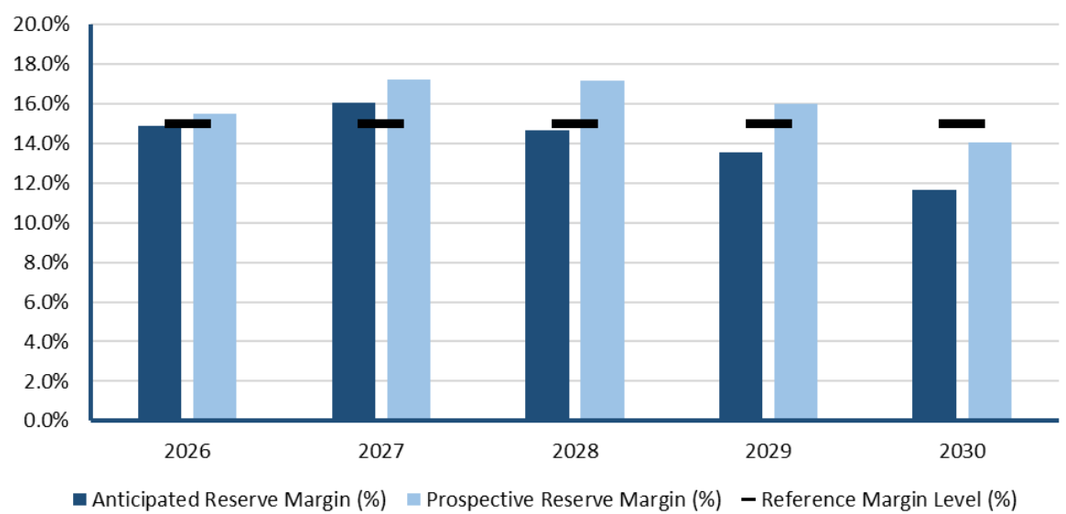


SERC-Central

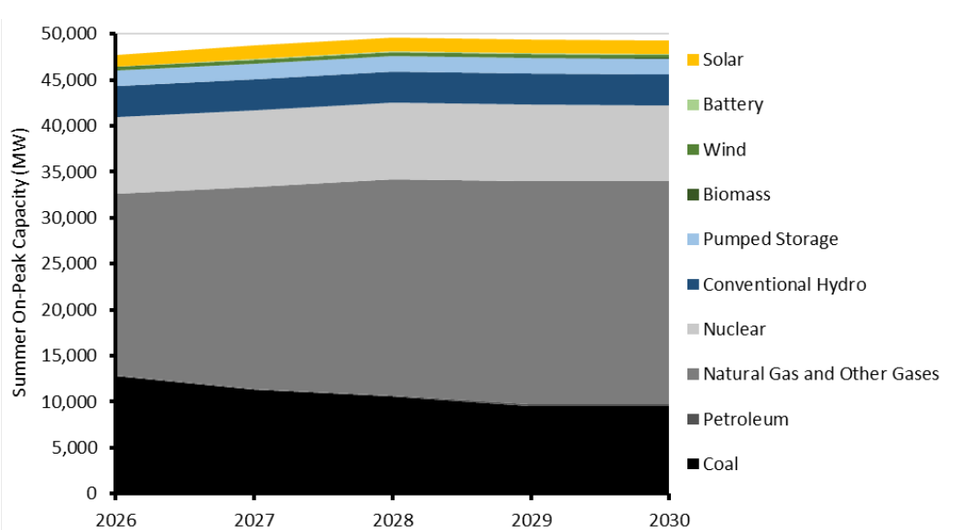
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of 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.

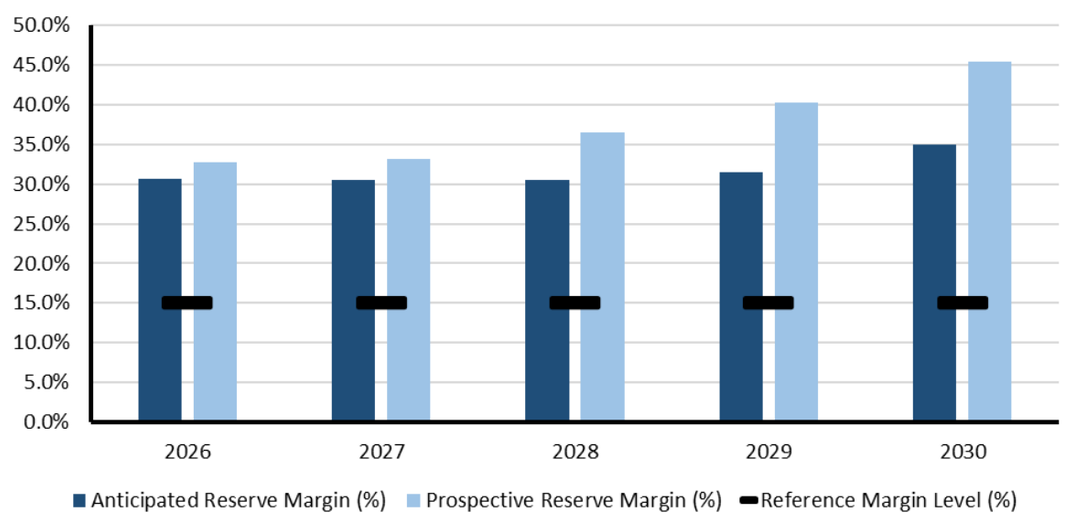


SERC-East

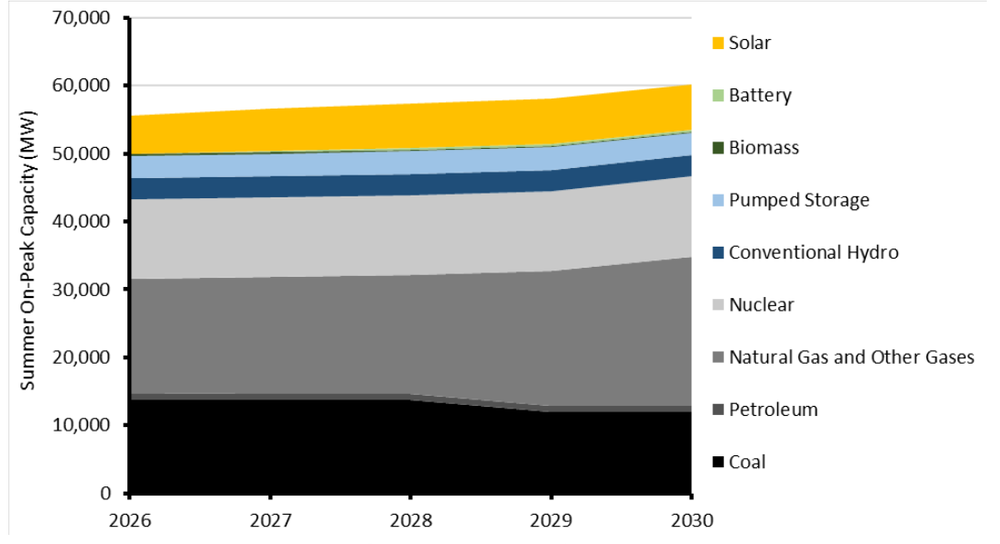
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible 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:

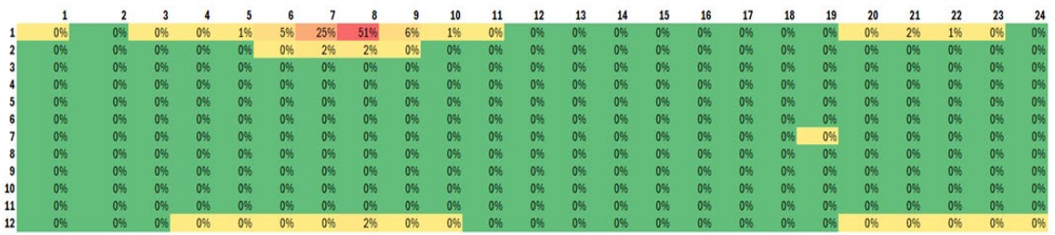
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also 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

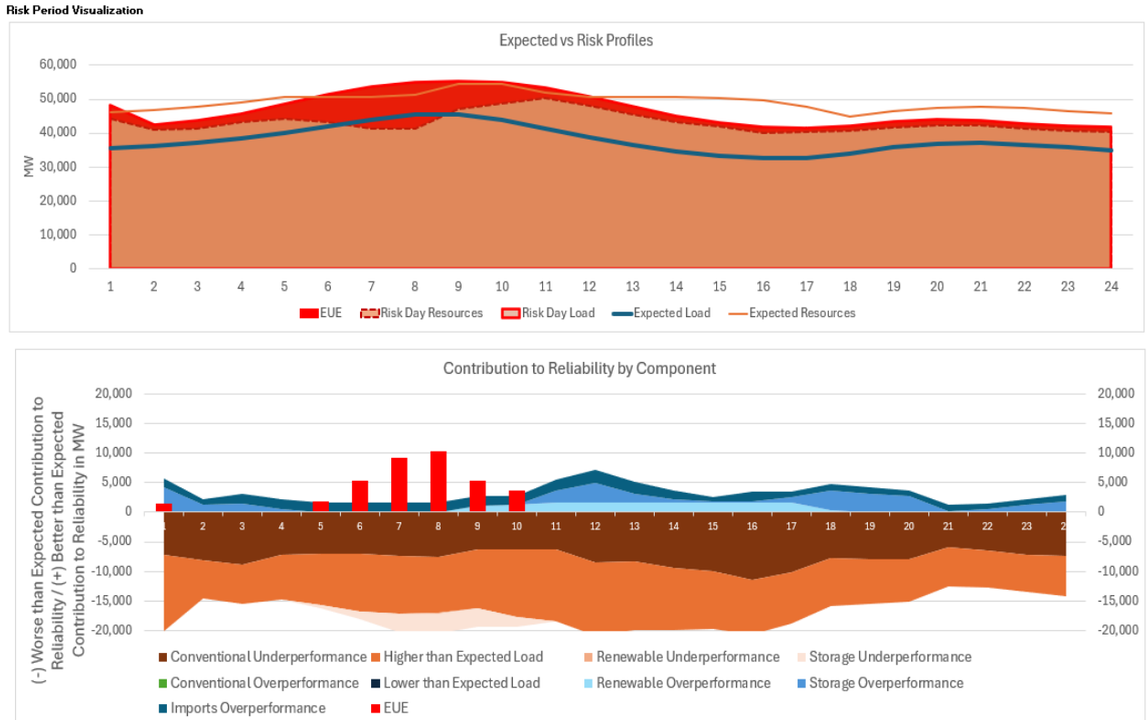
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	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

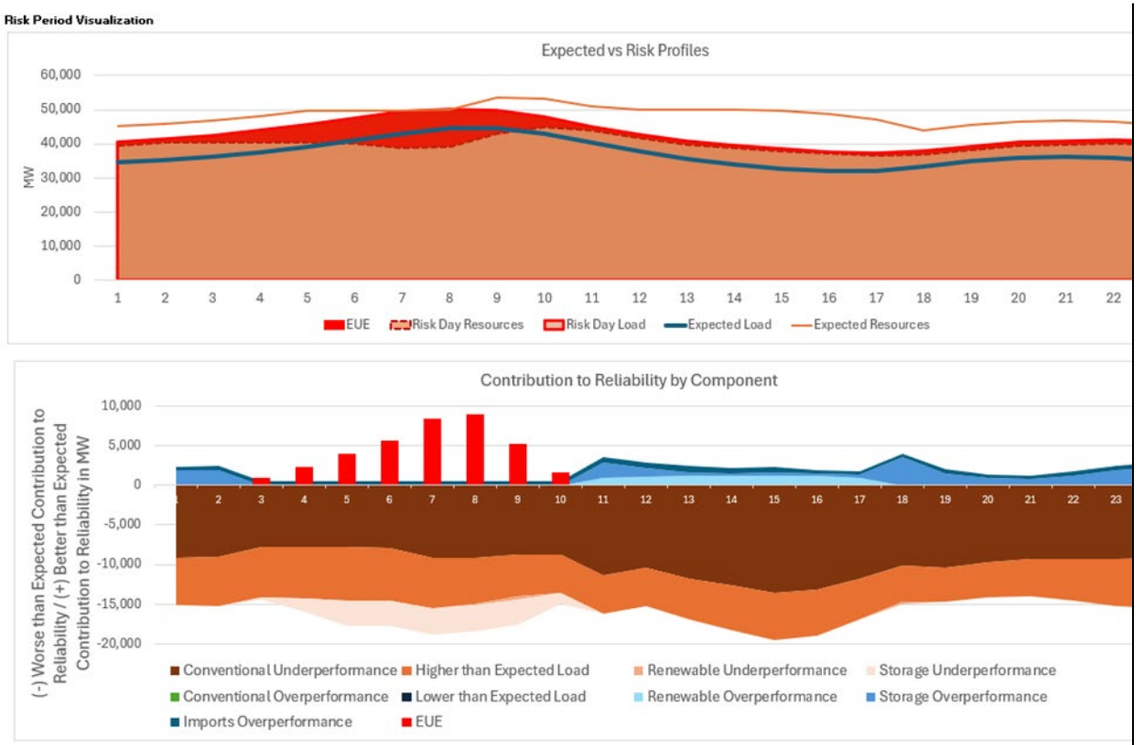
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



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.

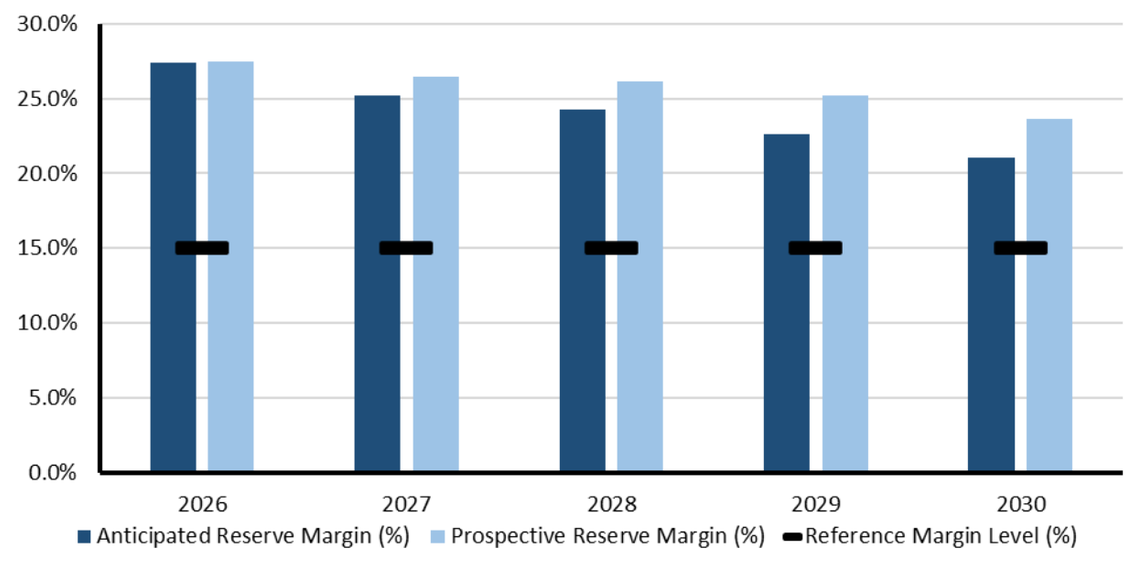


SERC-Florida Peninsula

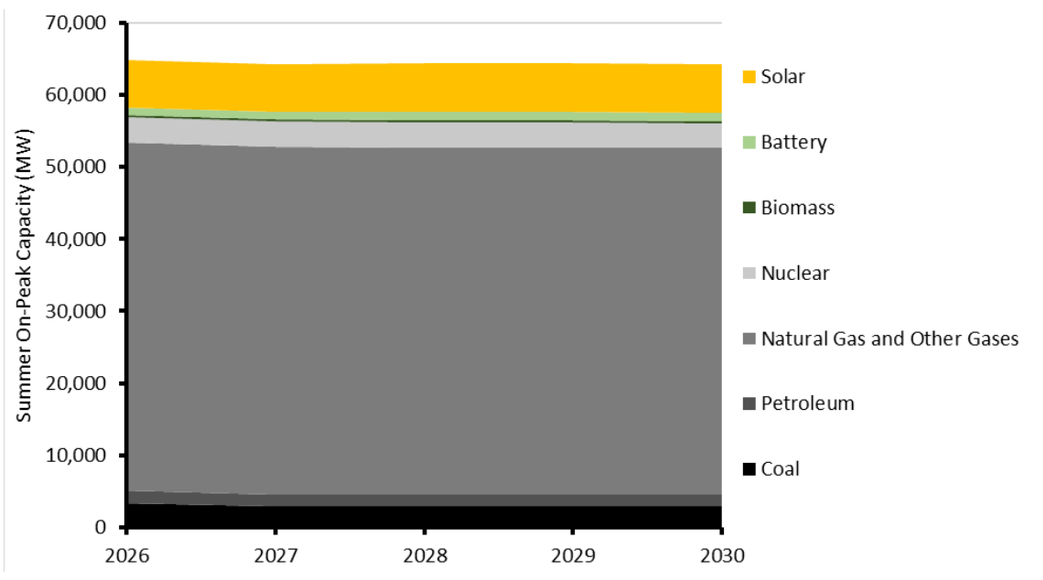
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across 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.					

SERC-Florida Peninsula Assessment

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.

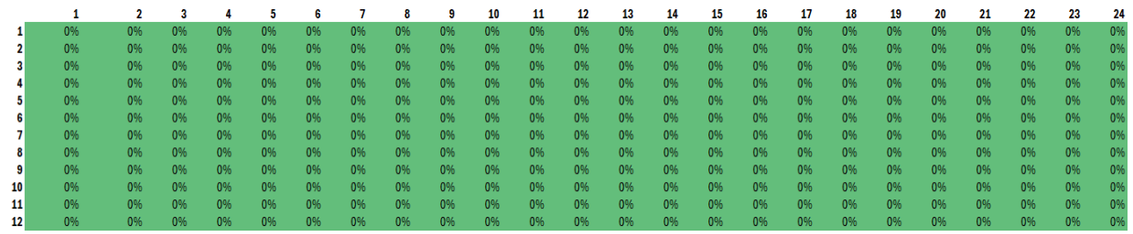
These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. 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.

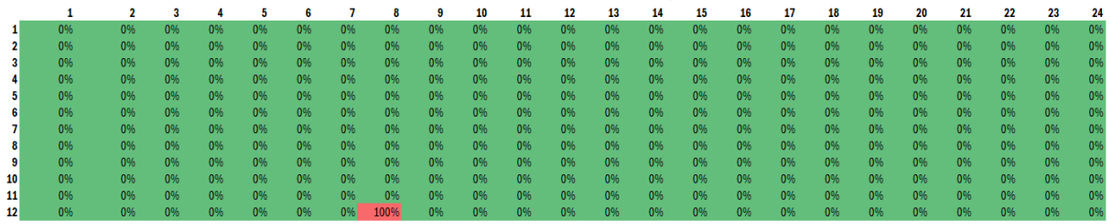
ProbA Results

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			



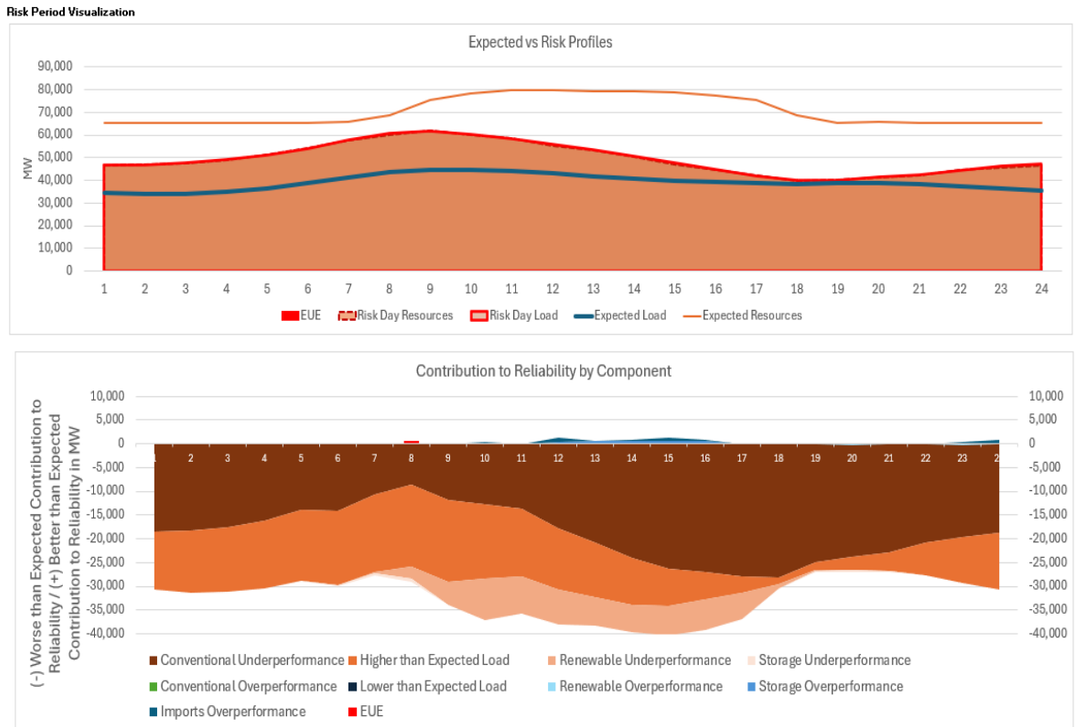
2027 EUE Heat Map



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.

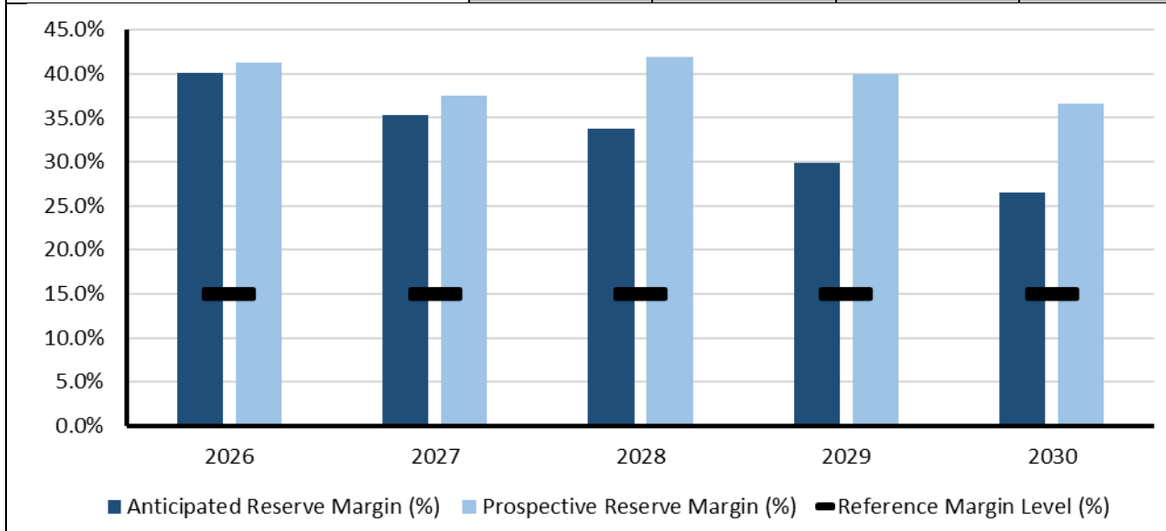


SERC-Southeast

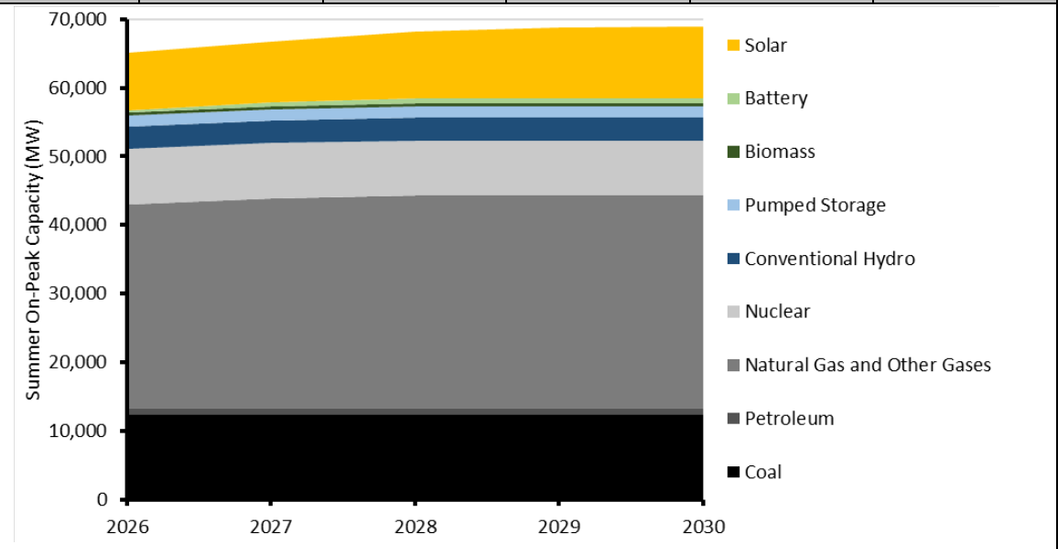
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. 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%

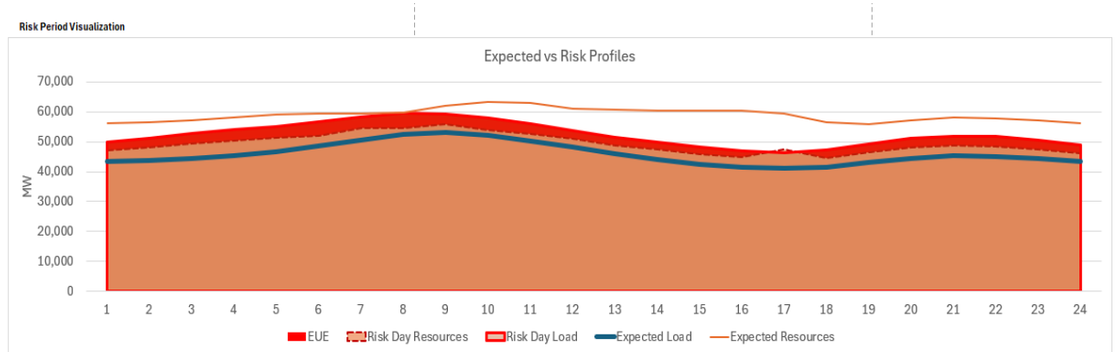
2027 EUE Heat Map

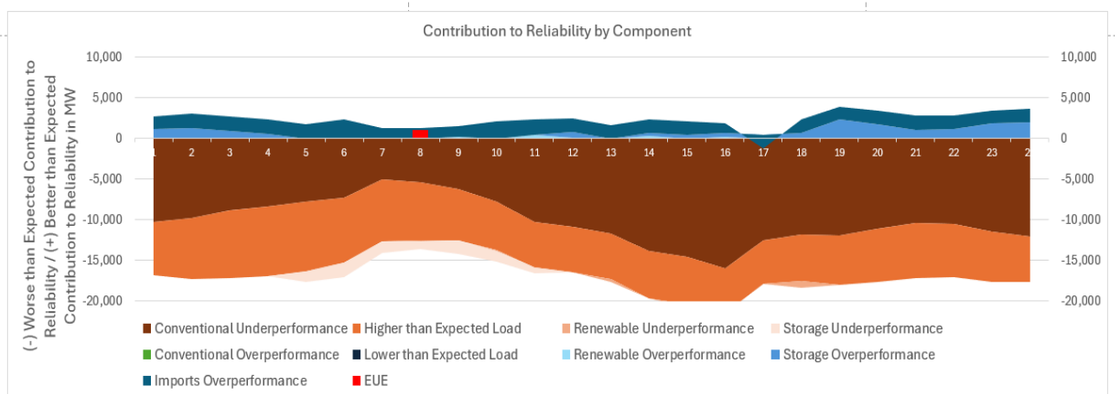
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events 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.

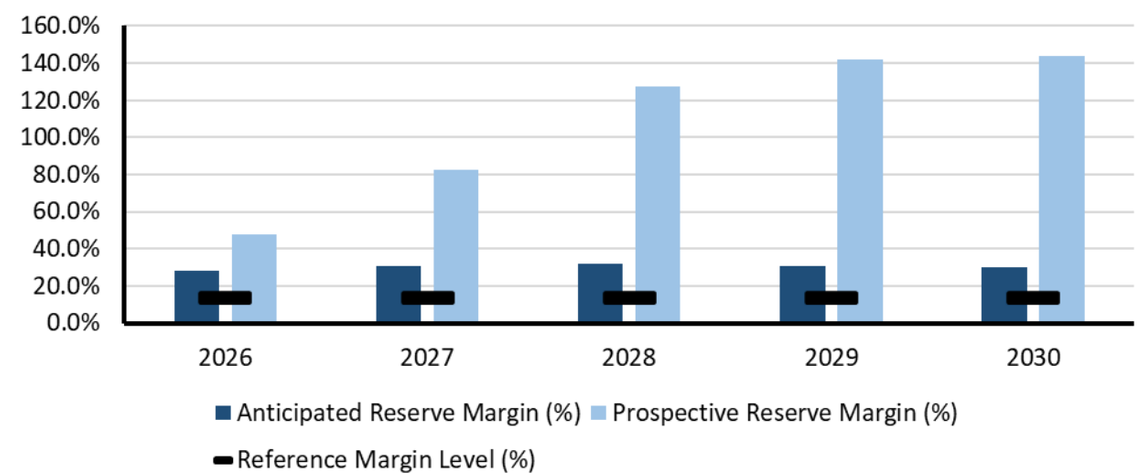


Texas RE-ERCOT

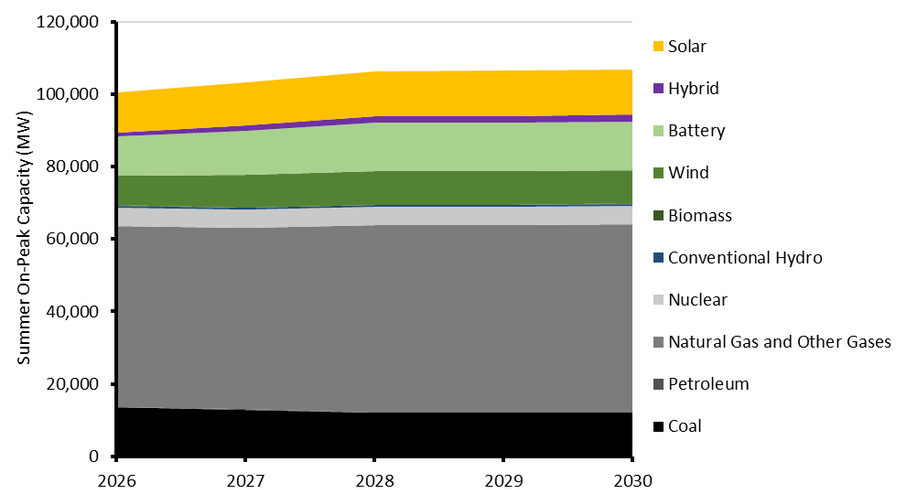
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million 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%	1%	2%	3%	4%	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.

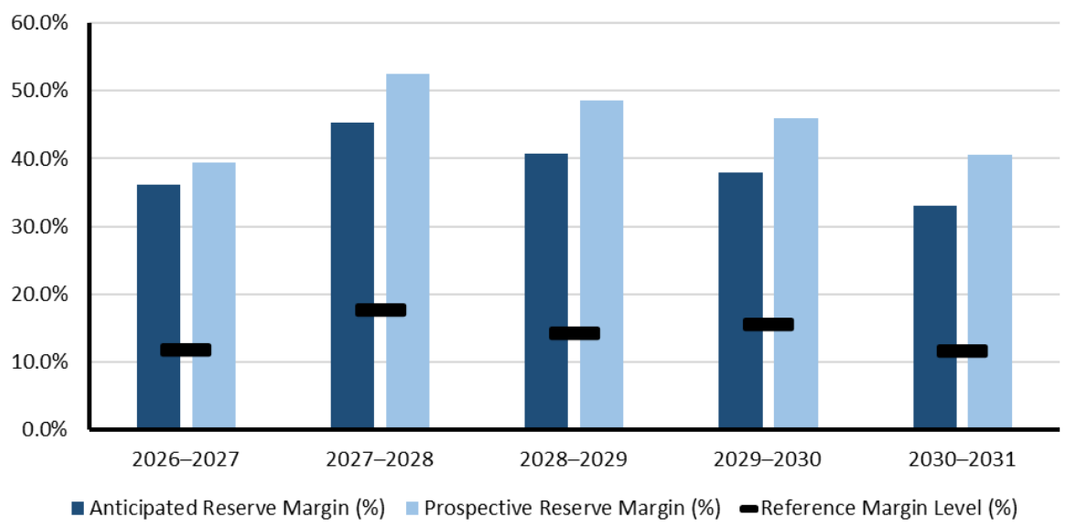


WECC-Alberta

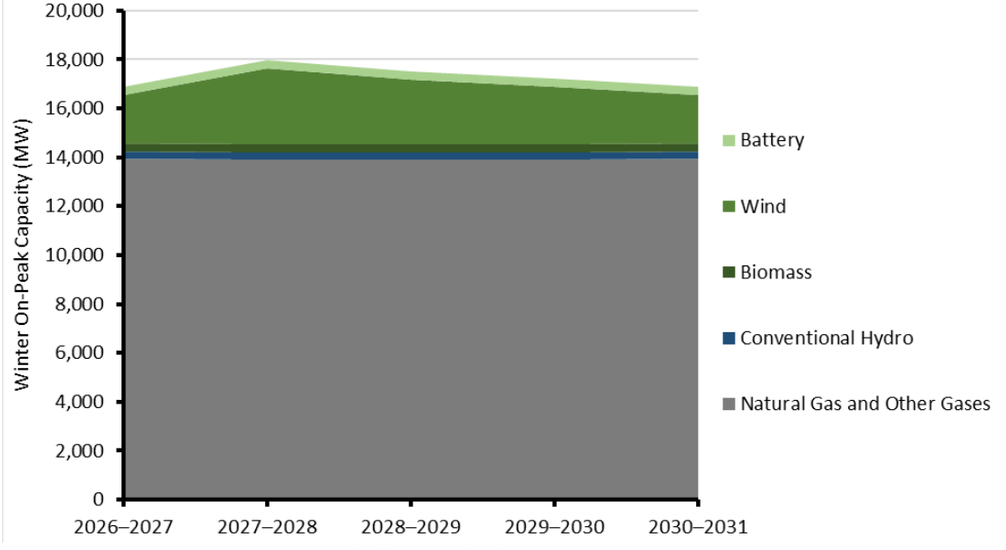
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability 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.

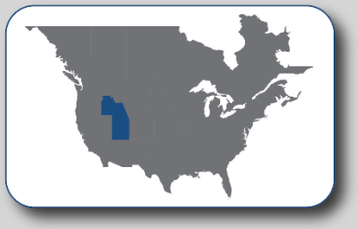
Energy Transfers

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.

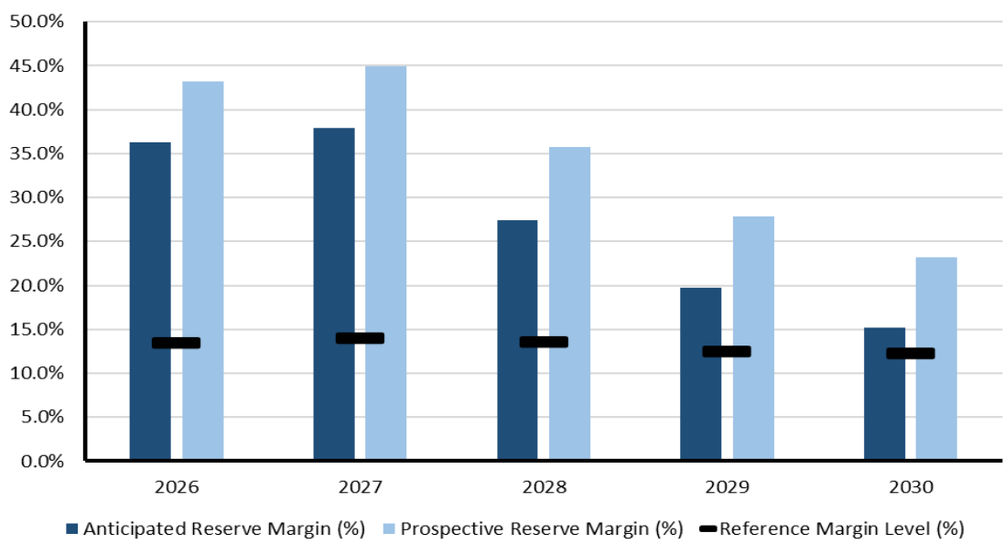


WECC-Basin

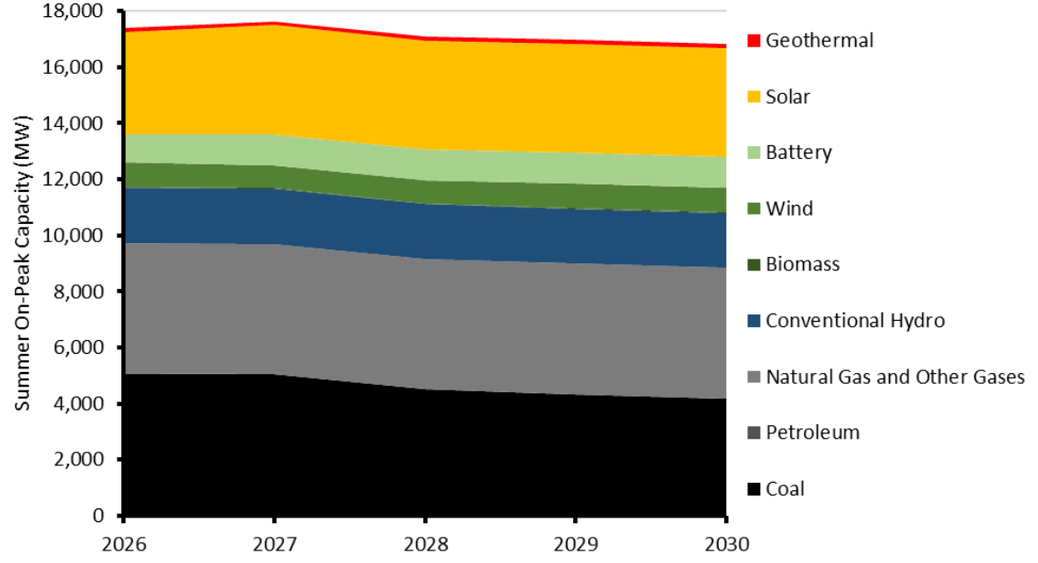
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is 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.

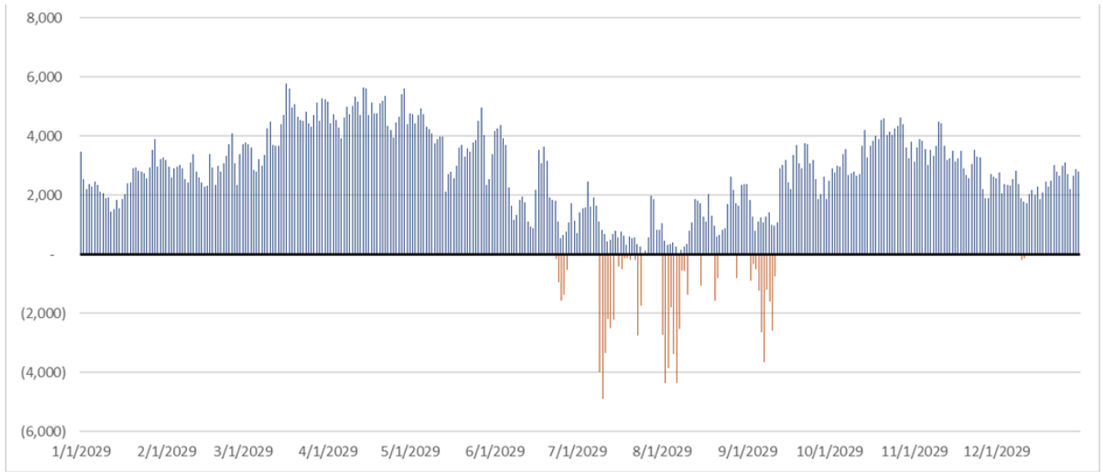
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
*** No prior results as the assessment area is new for the 2025 LTRA.**			

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.

Basin - 2027		Months												Basin - 2029		Months											
Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12	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	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		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		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		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		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		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		6	0	0	0	0	0	0	0	0	0	0	0	1
	7	0	0	0	0	0	0	0	0	0	0	0	0		7	0	0	0	0	0	0	0	1	0	0	0	2
	8	0	0	0	0	0	0	0	0	0	0	0	0		8	0	0	0	0	0	0	0	1	0	0	0	2
	9	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		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		11	0	0	0	0	0	0	2	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0		12	0	0	0	0	0	0	8	1	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0		13	0	0	0	0	0	1	9	2	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0		14	0	0	0	0	0	2	8	2	1	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0		15	0	0	0	0	0	3	8	3	1	0	0	0
	16	0	0	0	0	0	0	0	0	0	0	0	0		16	0	0	0	0	0	2	8	4	6	0	0	3
	17	0	0	0	0	0	0	0	0	0	0	0	0		17	2	0	0	0	0	4	11	14	8	0	0	5
	18	0	0	0	0	0	1	0	0	0	0	0	0		18	0	0	0	0	0	6	16	20	12	0	0	4
	19	0	0	0	0	0	1	1	0	0	0	0	0		19	0	0	0	0	0	7	17	22	9	0	0	3
	20	0	0	0	0	0	0	0	0	0	0	0	0		20	0	0	0	0	0	5	16	13	8	0	0	2
	21	0	0	0	0	0	0	0	0	0	0	0	0		21	0	0	0	0	0	0	7	9	1	0	0	0
	22	0	0	0	0	0	0	0	0	0	0	0	0		22	0	0	0	0	0	0	0	5	0	0	0	0
	23	0	0	0	0	0	0	0	0	0	0	0	0		23	0	0	0	0	0	0	0	3	0	0	0	0

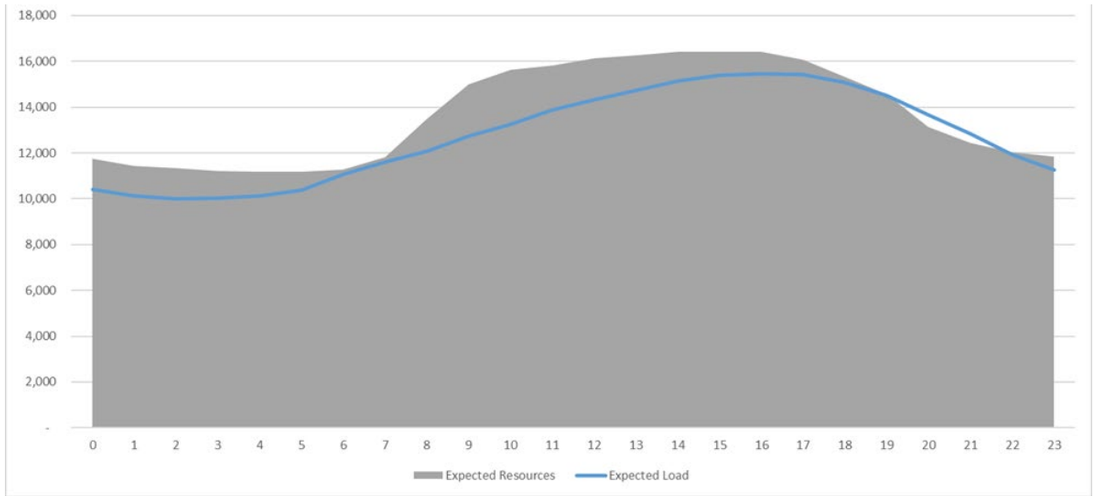
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

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.

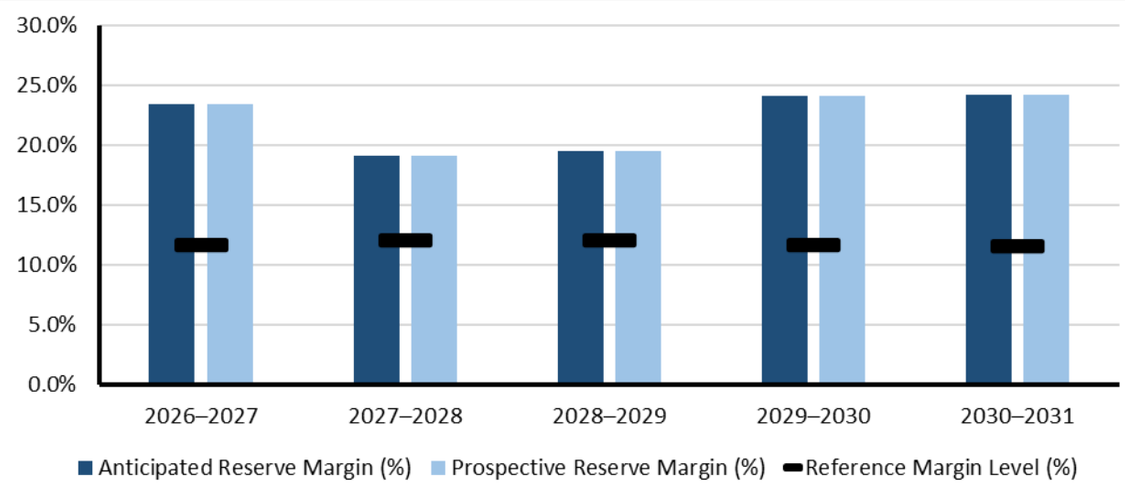


WECC-British Columbia

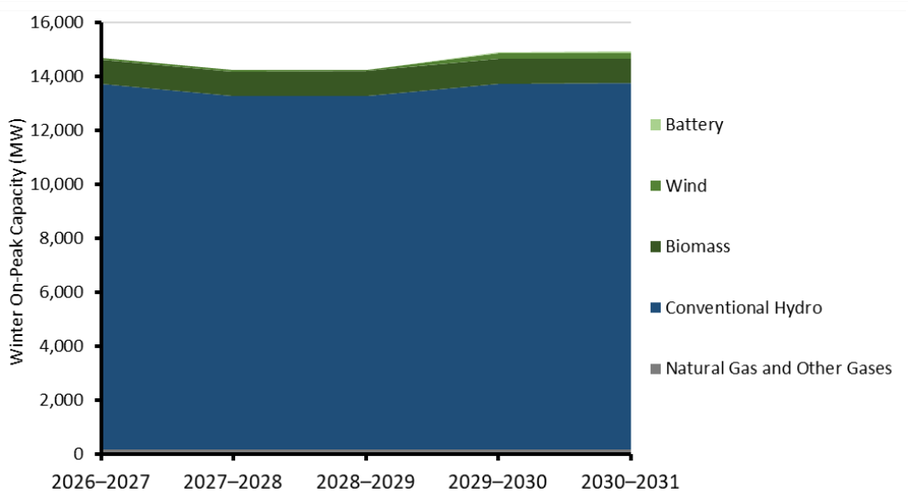
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the 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.

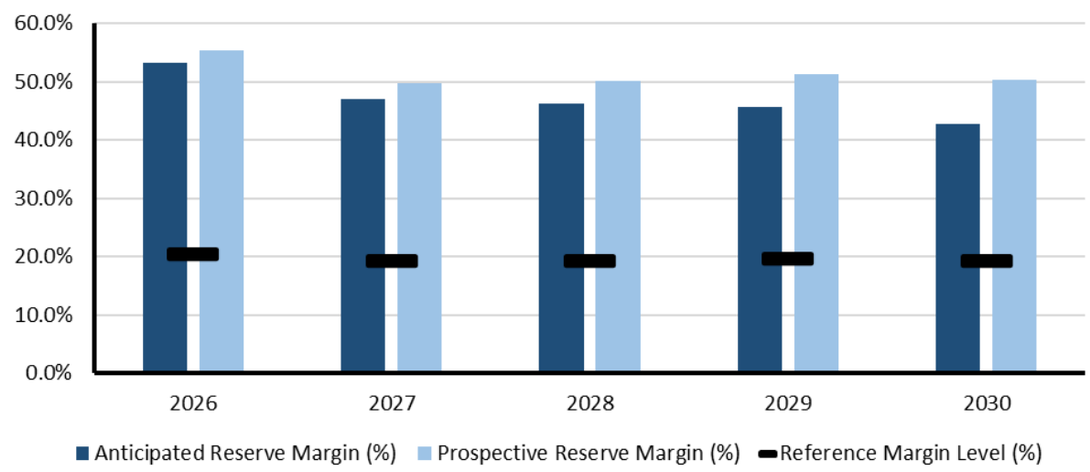


WECC-California

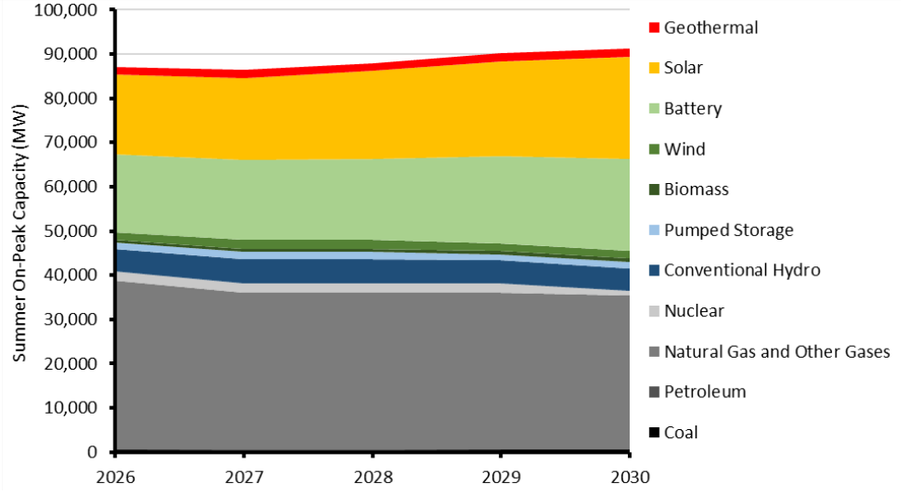
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock 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.

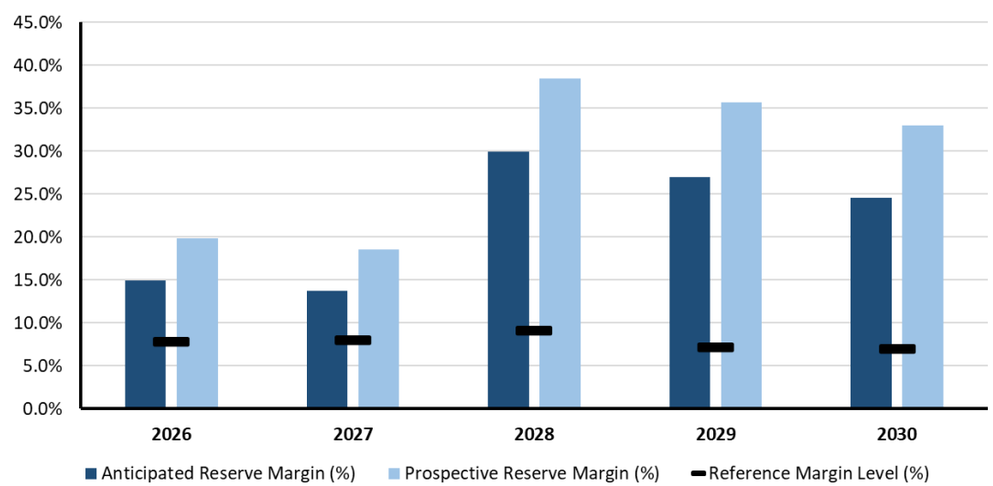


WECC-Mexico

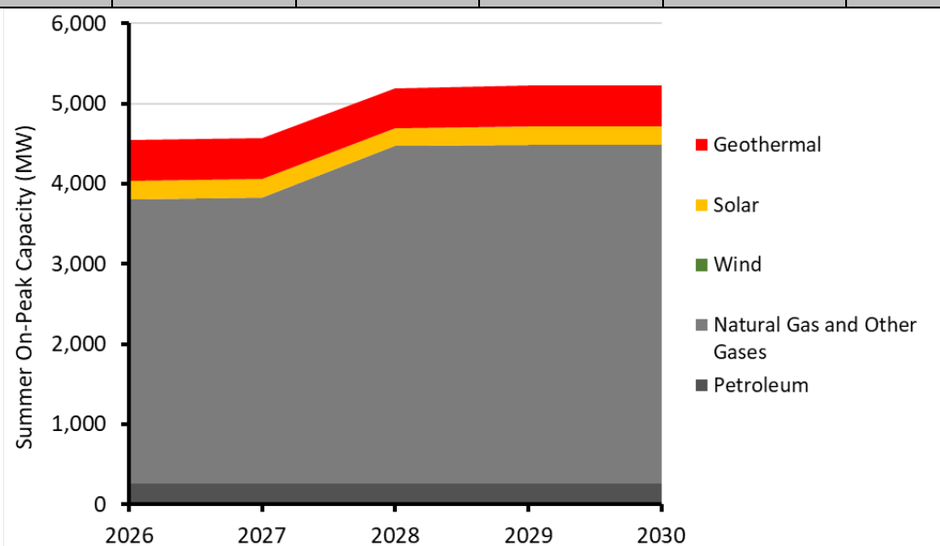
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting 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.

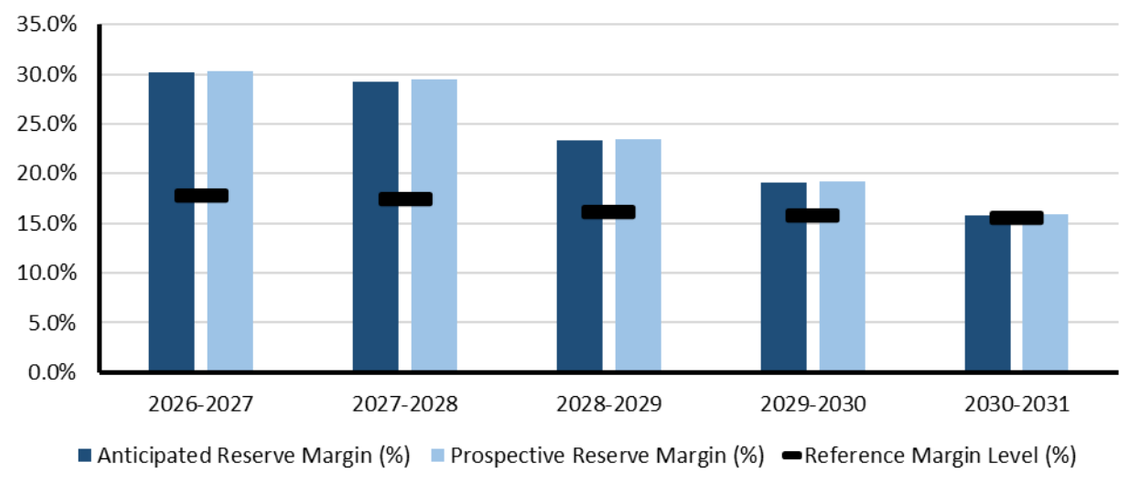


WECC-Northwest

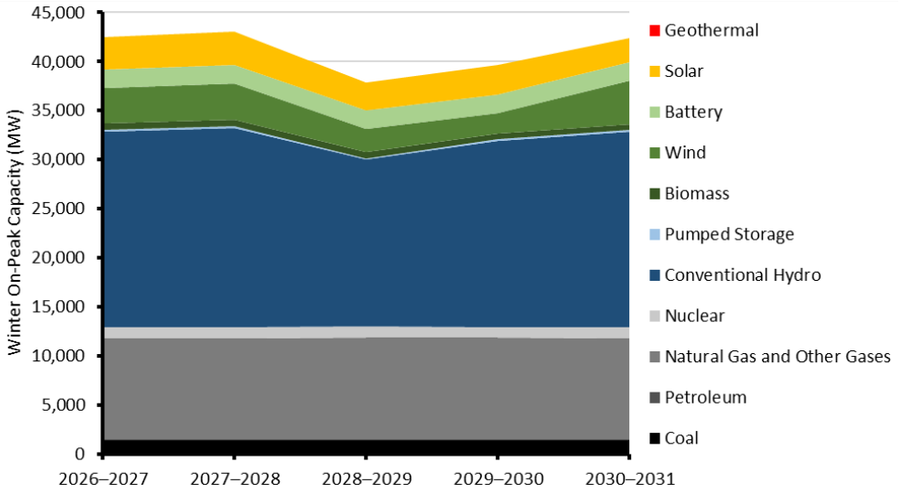
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for 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

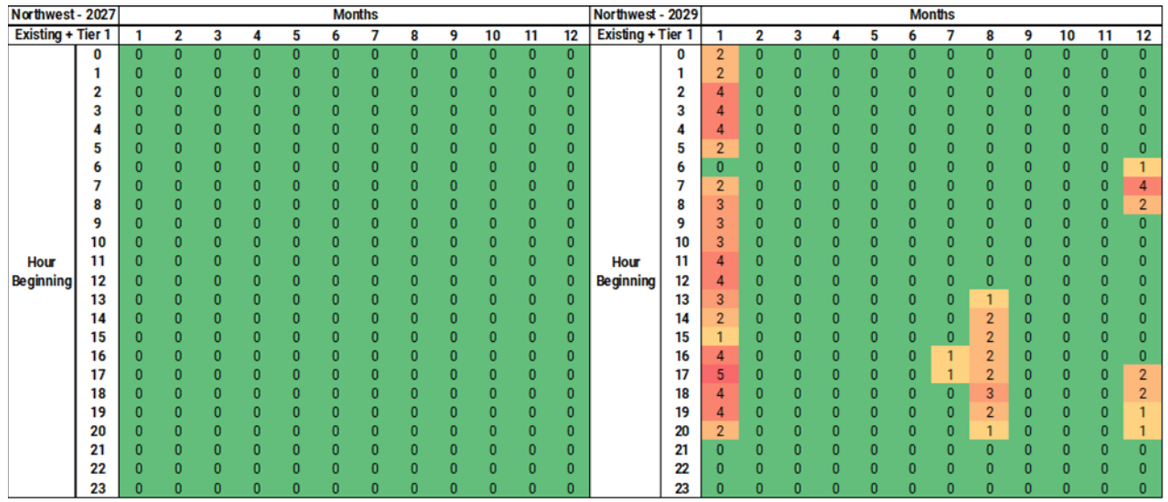
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

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.			

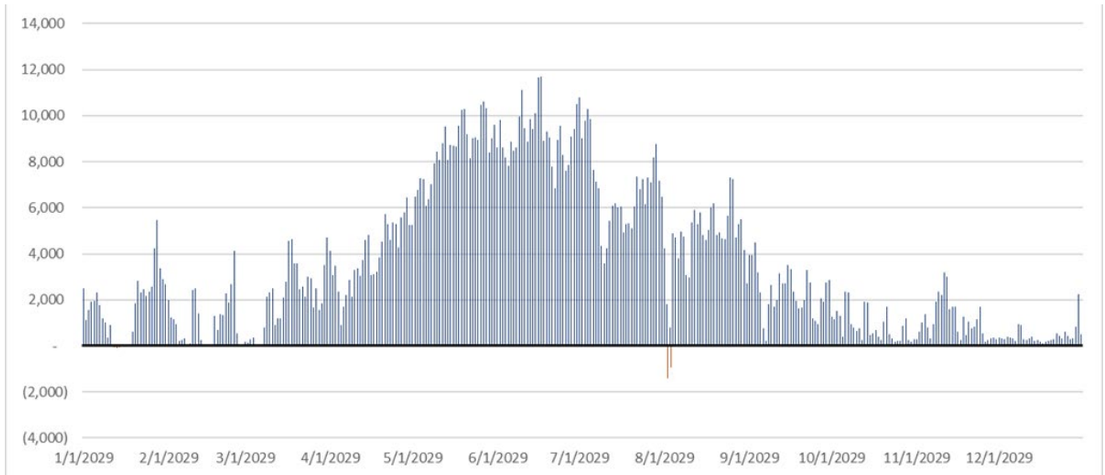
Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also 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												Northwest - 2029	Months										
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
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
1	0	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	0	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	0	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	0	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	0	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	0	6	0	0	0	0	0	0	0	0	0	0	0	1
7	0	0	0	0	0	0	0	0	0	0	0	0	7	2	0	0	0	0	0	0	0	0	0	0	4
8	0	0	0	0	0	0	0	0	0	0	0	0	8	3	0	0	0	0	0	0	0	0	0	0	2
9	0	0	0	0	0	0	0	0	0	0	0	0	9	3	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	10	3	0	0	0	0	0	0	0	0	0	0	0
Hour Beginning 11	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning 11	4	0	0	0	0	0	0	0	0	0	0	0
12	0	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	0	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	0	0	0	0	0	0	0	0	0	0	0	0	14	2	0	0	0	0	0	0	2	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	15	1	0	0	0	0	0	0	2	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0	16	4	0	0	0	0	0	1	2	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0	17	5	0	0	0	0	0	1	2	0	0	0	2
18	0	0	0	0	0	0	0	0	0	0	0	0	18	4	0	0	0	0	0	0	3	0	0	0	2
19	0	0	0	0	0	0	0	0	0	0	0	0	19	4	0	0	0	0	0	0	2	0	0	0	1
20	0	0	0	0	0	0	0	0	0	0	0	0	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	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	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	23	0	0	0	0	0	0	0	0	0	0	0	0

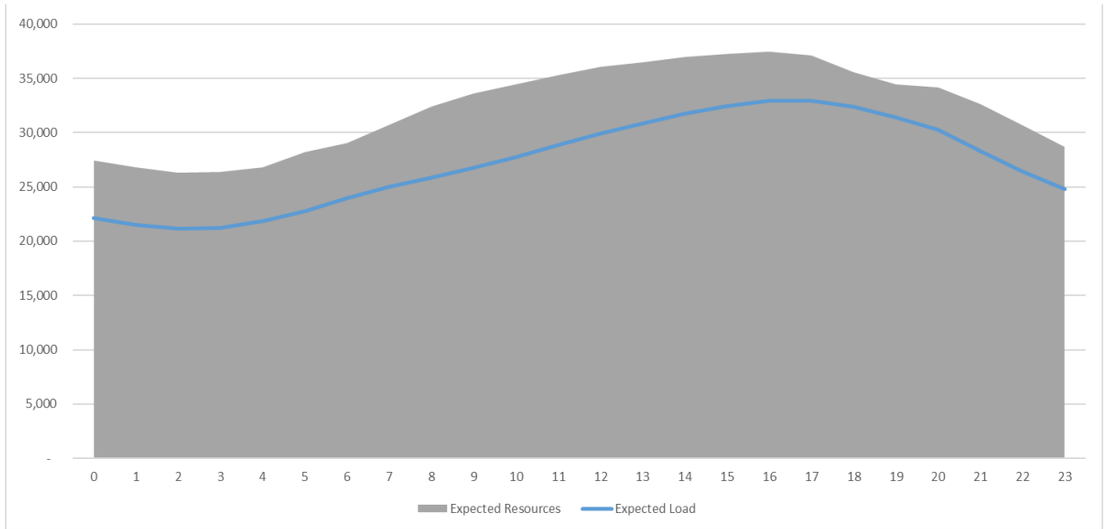
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

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.

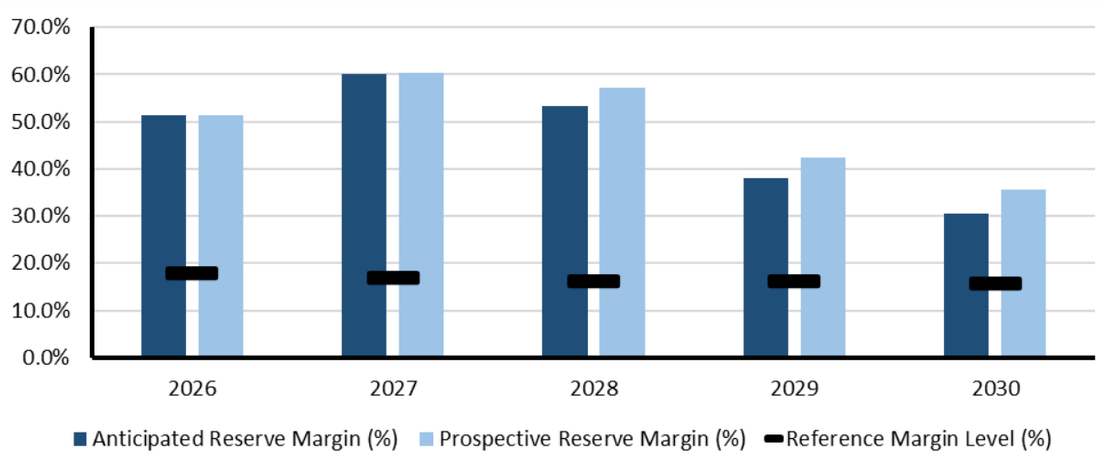


WECC-Rocky Mountain

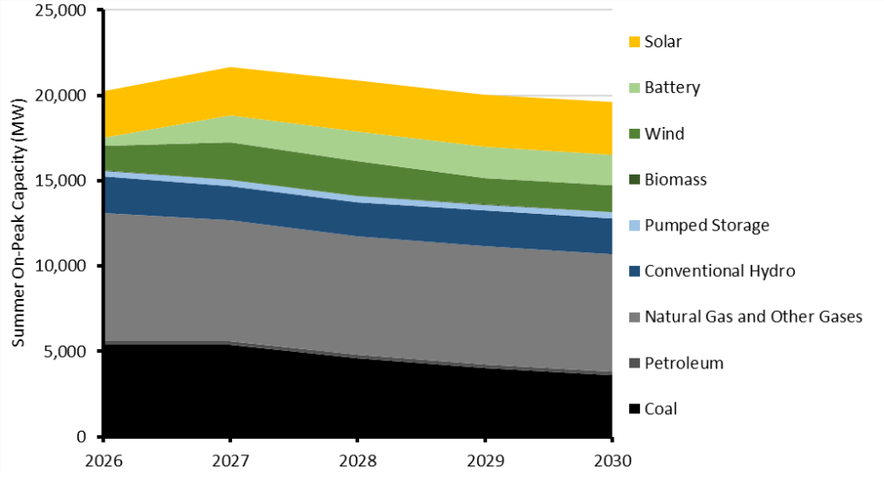
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and 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.

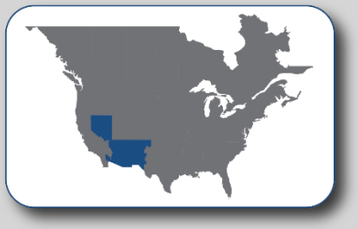
Demand-Side Management
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

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.

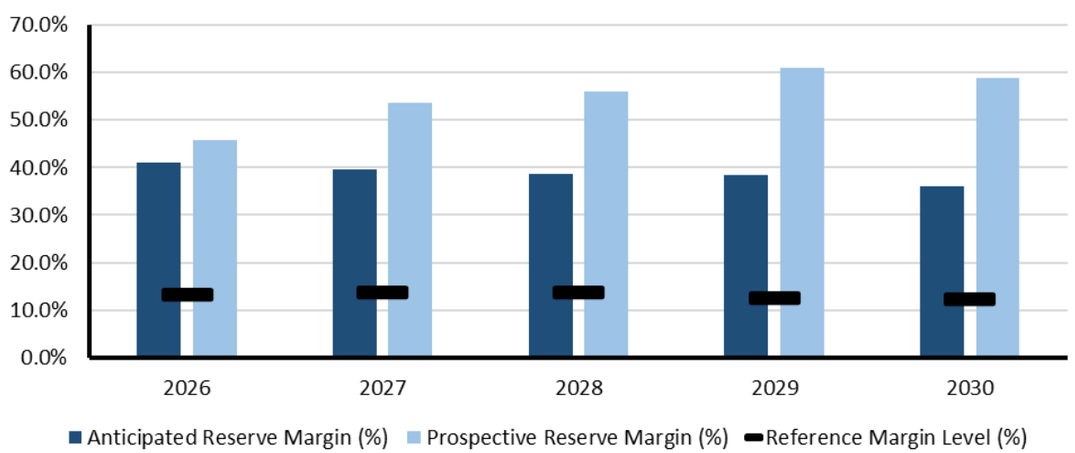


WECC-Southwest

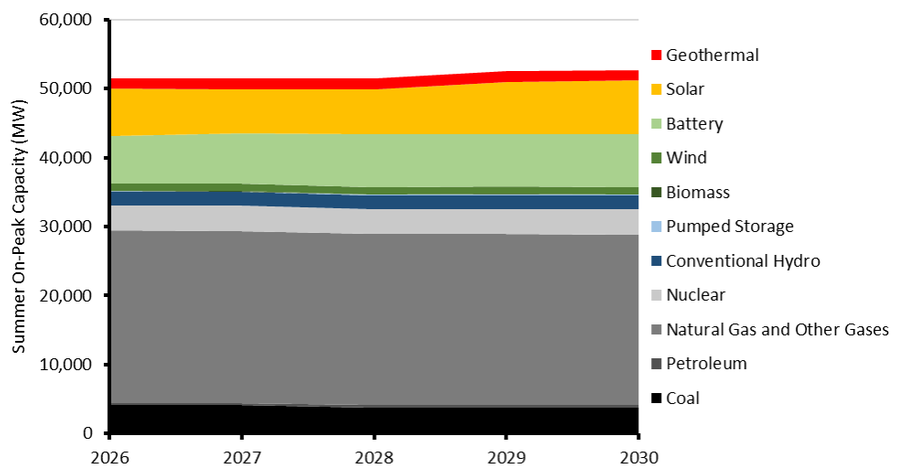
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for 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. 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 Summer: 8.1% Fall: 14.9% Winter: 19.1% 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. 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 NERC Alerts Event Analysis Reports 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. 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 NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned 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. 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. 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. 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] 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 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 Reliability Guidelines 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)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-147:
Grid Strategies Analysis of NERC LTRA

Grid Strategies

Review of NERC's 2025 Long-Term Reliability Assessment

Adria E. Brooks, Michael Goggin, John D. Wilson

March 5, 2026

Prepared for Earthjustice, Natural Resource Defense Council, Sierra Club, and Environmental Defense Fund

Table of Contents

1. Executive Summary
2. Generation resource assumptions
3. Interregional transmission assumptions
4. Demand assumptions
5. Extreme event energy adequacy
6. Conclusions and solutions
7. Methodology

Executive Summary

The NERC LTRA assesses future regional resource adequacy risk. Re-assessment using a more complete accounting of generation, imports, and demand from other data sources results in lower risk.

Overall, the LTRA resource margins are much tighter than what may occur for four reasons.

First, the LTRA underestimates likely-to-connect power resources. Power resources in advanced development stages are projected to provide enough capacity to resolve the majority of shortfalls identified in the LTRA.

Second, the most significant risk to resource adequacy shortfalls are delays to generator interconnection. Actions that delay interconnection study, permitting, and/or construction for generation facilities increase the likelihood of shortfalls.

Third, the LTRA underestimates imports from one region to another. At levels seen historically during extreme events, these are sufficient to further alleviate resource inadequacy.

Furthermore, additional interregional transmission would lessen shortfall risk. The NERC-identified interregional transfer capability additions would help resolve many of the identified seasonal capacity and energy shortfalls.

Fourth, data centers may require significantly less power than expected. Combined with the other three corrections, this scenario could allow all regions to meet 2030 peak summer load and reserve needs.

With a clearer vision of the future and rapid action, the grid could be even more reliable in five years than it is today.

NERC's 2025 Long-Term Reliability Assessment is too pessimistic. This analysis explores three major categories of input assumptions that impact the regional risks NERC identified.

North American Electric Reliability Corporation (NERC)'s Long-Term Reliability Assessment (LTRA) importantly captures potential reliability issues for a snapshot in time. NERC relies on utility-reported input data in making its assessments. This data, by definition, does not account for national power sector trends or limitations—such as double-counting of prospective demand or generation—that can have large impacts on future risk.

In this analysis we compare NERC's input data and assumptions against other sources to explore how changes to inputs impact the severity of risk identified in the LTRA. We explore three categories of inputs: demand, generation resources, and interregional transmission.

As the LTRA highlights, reserve margins—the difference between electricity demand and available supply—are tightening across the country. We find that while these margins are tightening, the severity of that risk is likely less than reported in the LTRA.

Three major factors:



Generation Resources



Interregional Transmission



Demand for electricity

GridStrategies

SOURCE | NERC "2025 Long-Term Reliability Assessment (LTRA)" (Jan. 2026)

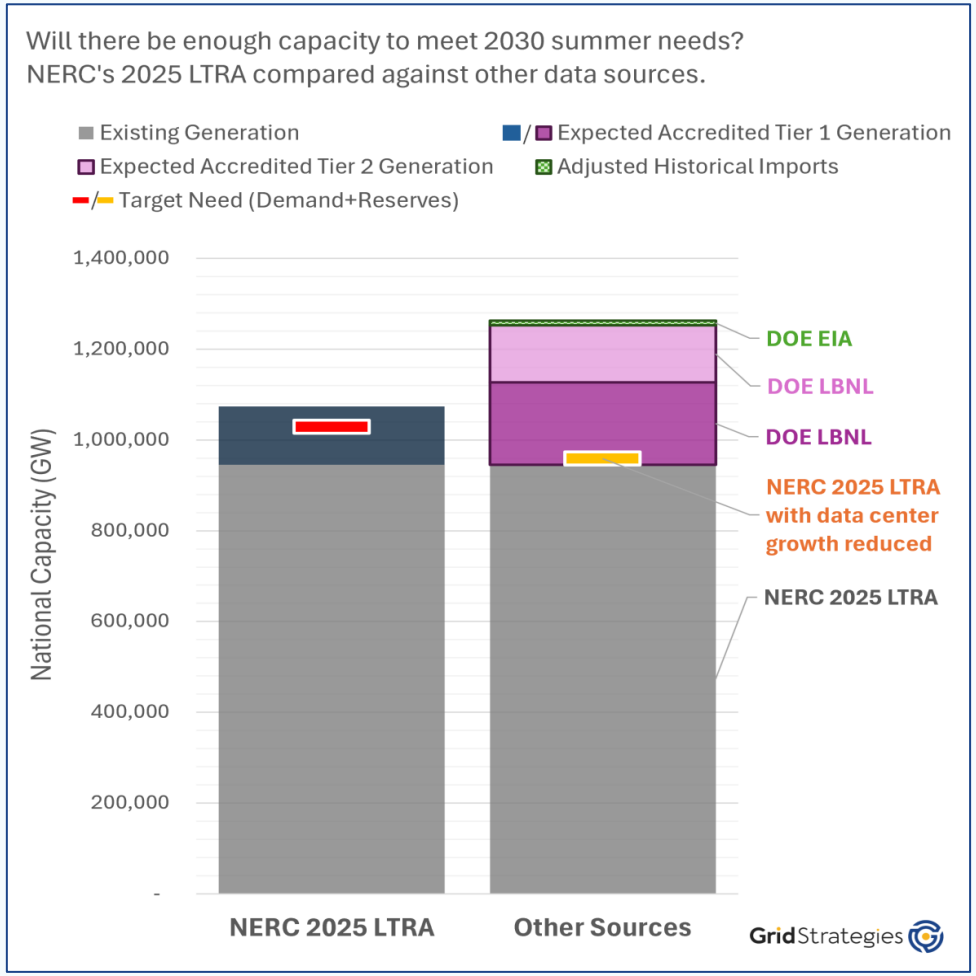
NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- The LTRA generation forecast is based on an incomplete accounting of nearly built generation projects. A more reasonable expectation for generation growth can be determined from each region's interconnection queue.
- The LTRA import forecast excludes the opportunity for increased imports from new interregional transfer capability.
- The LTRA demand forecast is supplied by utilities and regional planners. The vast majority of the load growth in the LTRA forecast is based on utility large load forecasts. Some of this load is uncommitted and may not materialize or it may curtail during peak periods.

The combination of low generation, low import, and high demand assumptions used in the 2025 LTRA resulted in resource margins appearing tighter than may actually materialize.

A comparison of the aggregated resource margins from NERC's LTRA and other national, reputable data sources, which account for the above three factors, is shown to the right. This chart is explained in the Methodology.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025; Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Implementing currently available solutions will help all regions alleviate the identified capacity and energy risks.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

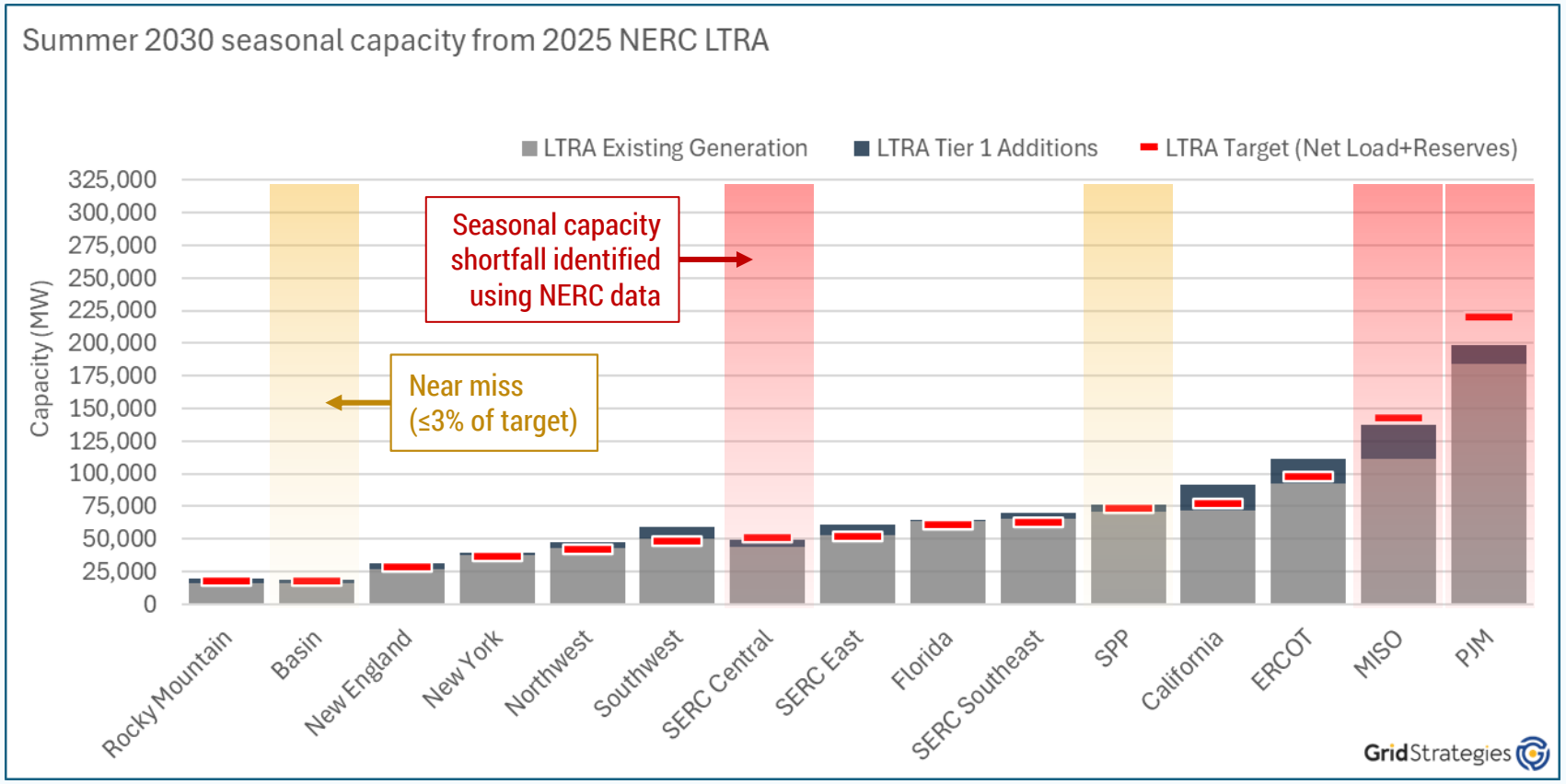
- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Generation Resource Assumptions

NERC only considered resources with executed interconnection agreements when determining shortfall risk.

All resources must undergo interconnection studies to identify any grid upgrades that may be necessary to reliably connect. At the end of the interconnection queue process, an interconnection agreement (IA) is executed. NERC considers any resource that has an executed IA as **Tier 1**.

To be resource adequate, a region must have enough future capacity and imports to meet load and reserve margins ("target"). NERC only counts Tier 1 resources toward future resources in the LTRA. NERC identifies three regions* that may be short of 2030 summer capacity needs using its assumptions. Two regions only exceed their target by less than 3%, marked here as "near miss" regions.



*NERC did not identify SERC Central as a heightened risk region though it is shown to be short of future capacity using the LTRA source data, perhaps because they did not identify elevated energy inadequacy risk despite the seasonal capacity shortfall in the region. We highlight it as elevated risk given the identified seasonal capacity shortfall.

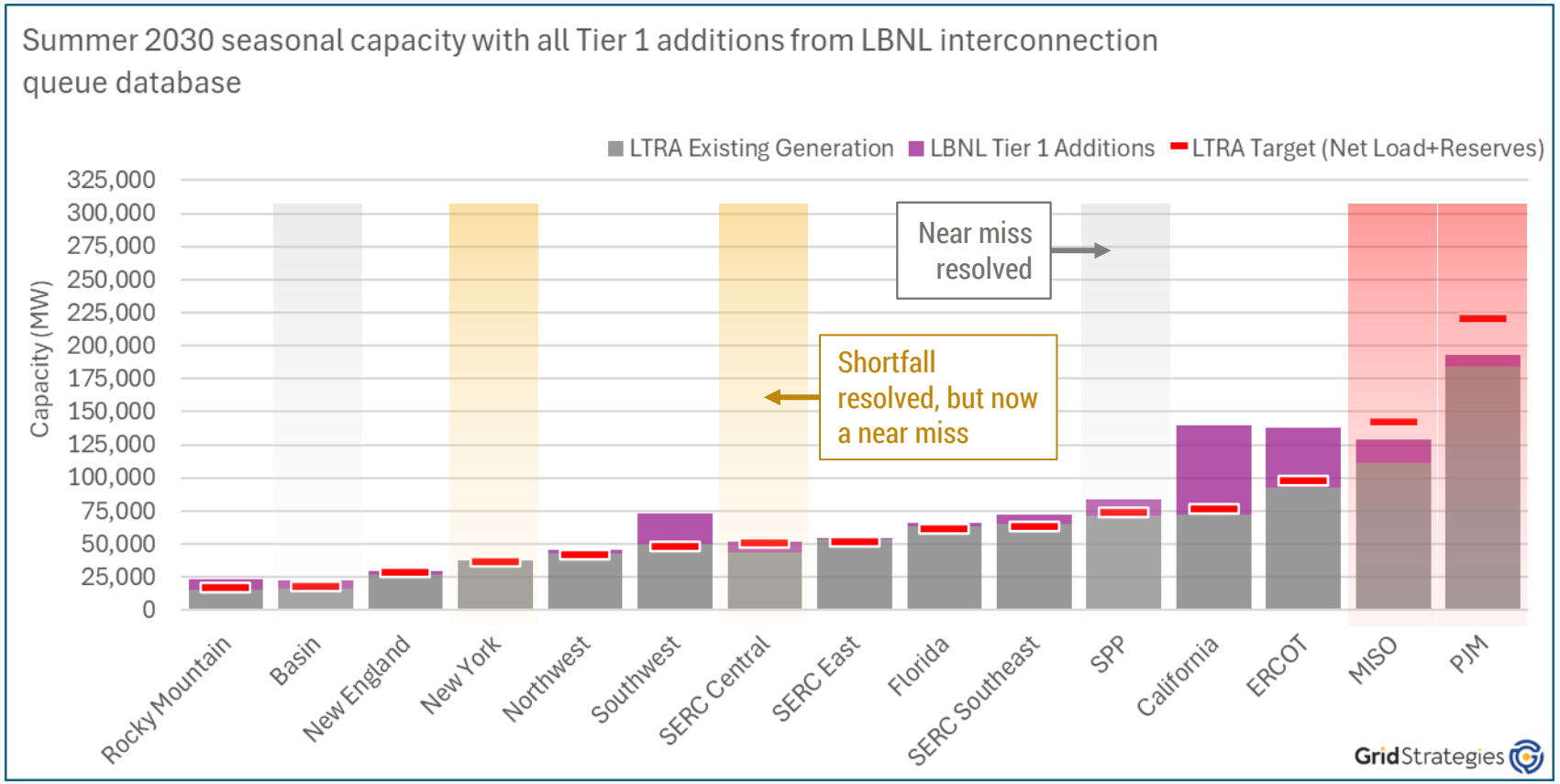
GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "2025 Electricity Supply & Demand (ES&D)" (Jan. 2026)

The amount of resource capacity with executed interconnection agreements in the LTRA is lower than that compiled by LBNL.

The U.S. Department of Energy (DOE)'s Lawrence Berkley National Laboratory (LBNL) tracks interconnection queue data across all regions and is a reputable source of high-quality data. The LBNL data suggests more accredited **Tier 1** resource capacity is available nationwide than is recorded in the LTRA, though regional allocations vary. The mismatch in data could be due to different processing methods, collection periods, and, importantly, resource accreditation methods.*

Using the LBNL data paints a different future risk picture than the LTRA—only two regions show 2030 summer shortfalls. This highlights how sensitive risk assessments are to their input data.



*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. Utilities do not uniformly report seasonal or resource-specific accredited capacity to NERC for use in the LTRA, which, as NERC highlights, may inaccurately account for the capacity availability during peak load (LTRA at 9, 44, 60, 71, 76, 122). See the Methodology for more information.

GridStrategies

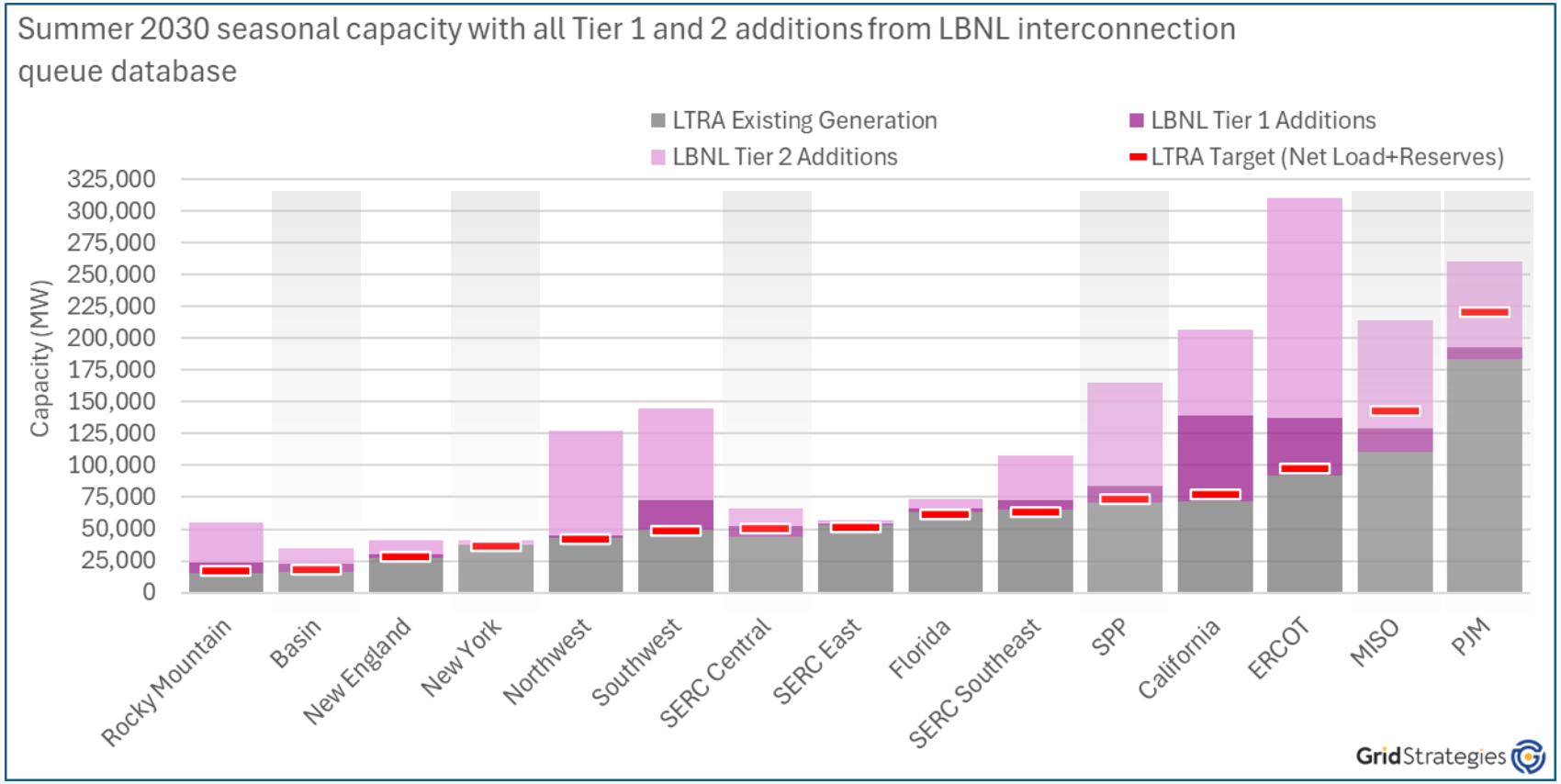
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (Aug. 2025)

There are more resources under development in each region than those with executed IAs. Providing a path to interconnection for these resources helps alleviate risk.

NERC considers any resource that has begun system studies, but has not yet completed them, to be a **Tier 2** resource. According to LBNL data, there is nearly five times the accredited Tier 2 resource capacity with planned in-service dates by 2030 nationwide than NERC-counted Tier 1 as well as three times the NERC-counted Tier 2 summer 2030 resource capacity.

NERC does not include any Tier 2 capacity in the LTRA shortfall analysis. Inclusion of this capacity suggests that regions could be at less risk of seasonal shortfalls than illustrated in the LTRA.

But this is only true if there are clear pathways for interconnection of these resources. LBNL research shows that generators are facing increasing delays in the interconnection study and post-study phases. These delays contribute to project cancellations, which is dangerous for seasonal resource adequacy.



GridStrategies

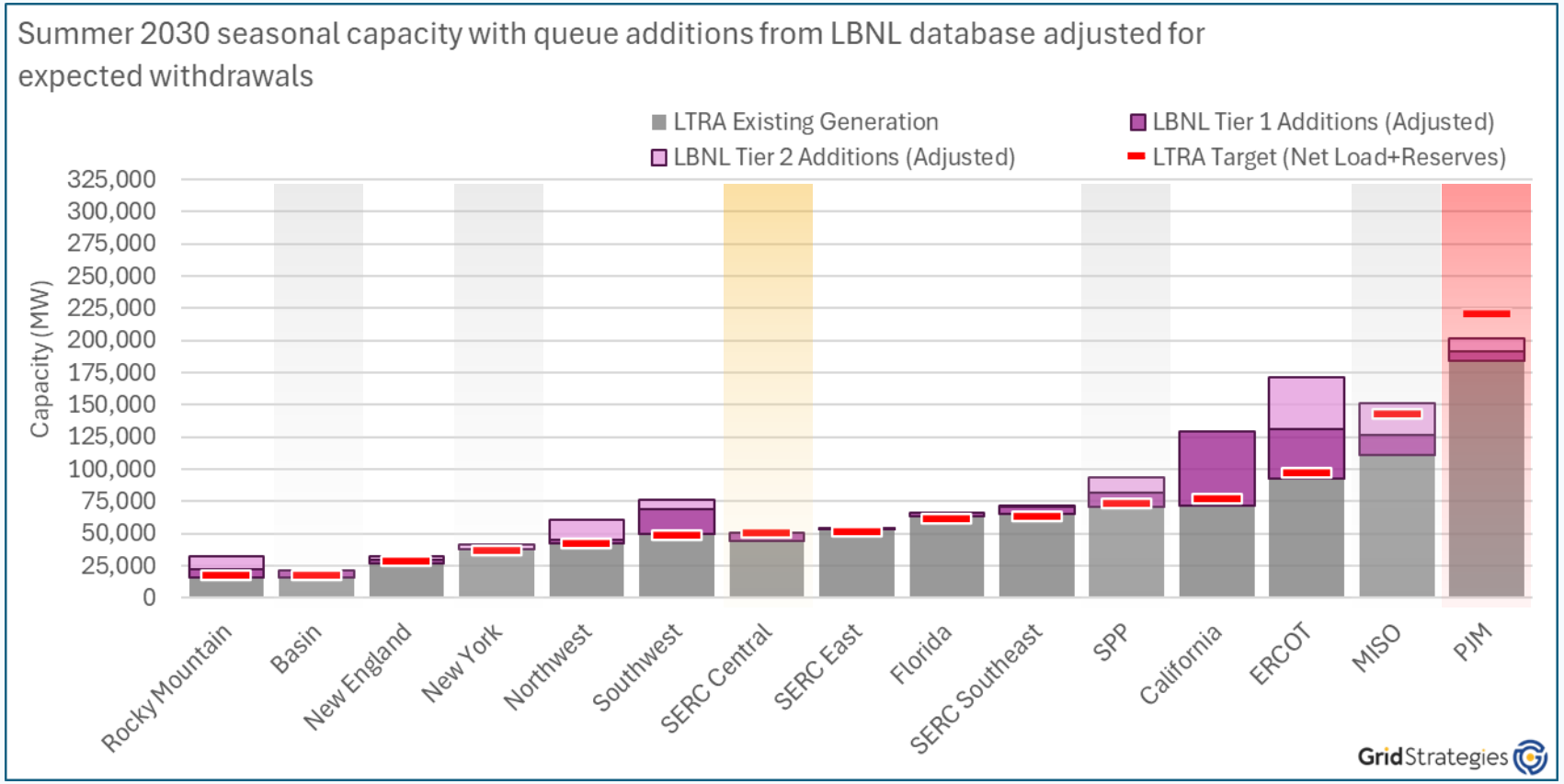
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Even when accounting for likely resource cancellations in the queue and post-queue phases, LBNL data suggests enough resources could connect to meet most regions' 2030 capacity needs.

It is unlikely that all Tier 1 and Tier 2 resources will connect to the grid. LBNL analysis shows as much as 85% of resources that enter the queues fails to connect to the grid ("withdrawal rates"), including facilities with executed IAs.

Rather than omit all Tier 2 data to account for the risk of cancellations (as done in the LTRA), we apply historic region-specific and phase-specific withdrawal rates to the LBNL data to estimate how much may connect to the grid by 2030.

Consideration of likely-to-connect resources currently in the interconnection queues resolves the majority of identified seasonal adequacy shortfalls. The resolution of shortfalls shown here is accomplished without a delay to announced resource retirements.



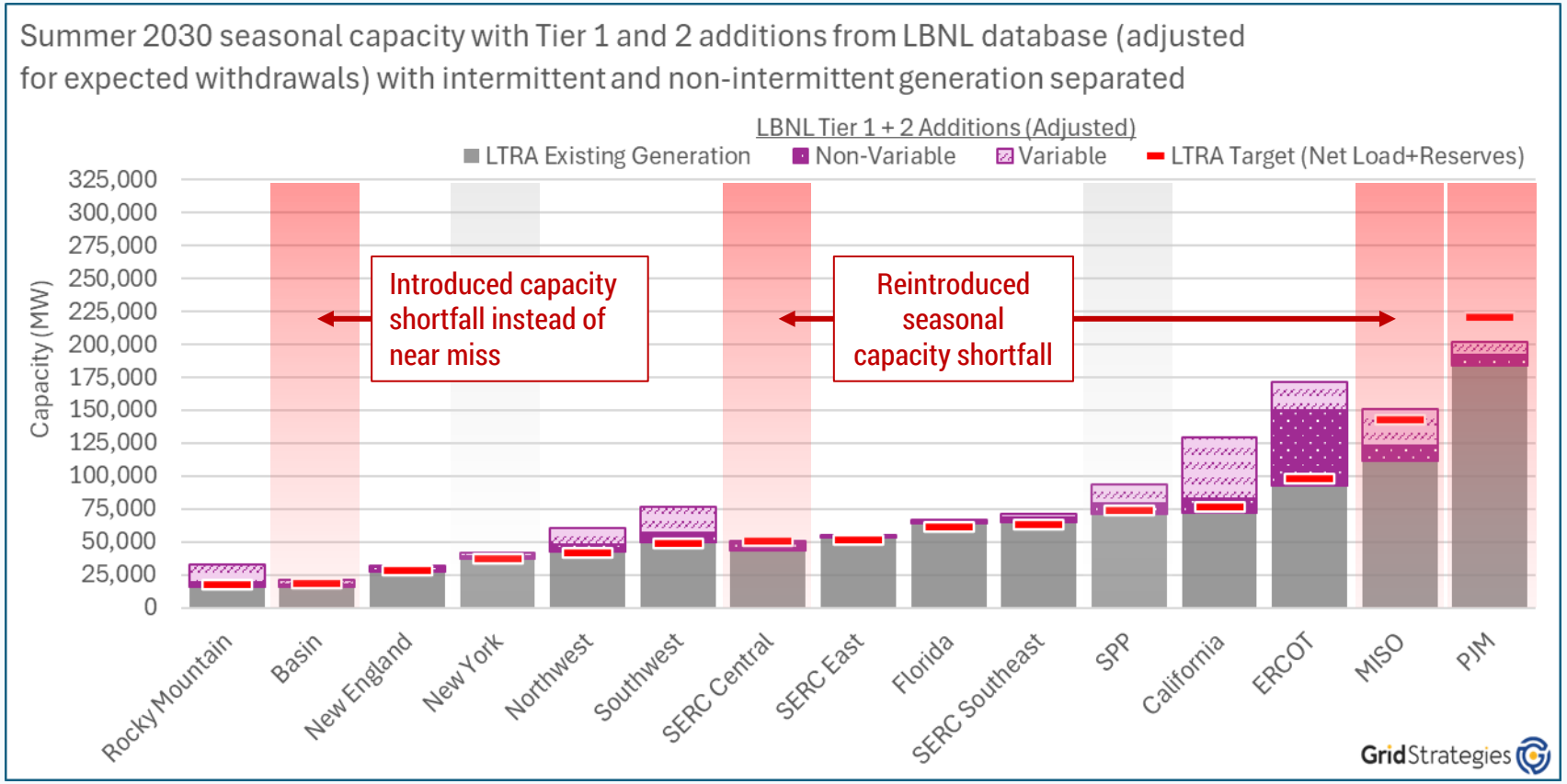
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Delays in the study, permitting, and/or construction phases to resources already in the queues—including wind and solar facilities—could jeopardize meeting regional seasonal capacity needs.

Additional permitting or equipment procurement steps applied to facilities increases their time to interconnection or results in project cancellation outright. Unnecessary hurdles for facilities waiting to interconnect could jeopardize huge amounts of resource capacity in advanced stages of development.

Shown here is the amount of likely-to-connect Tier 1 and 2 resource capacity from the LBNL data, broken out into variable (wind and solar) and non-variable resources.

Actions which delay permitting or construction for variable generation facilities could prevent large portions of the Midwestern, Southeastern, and Western regions from maintaining resource adequacy where they otherwise would be able to.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

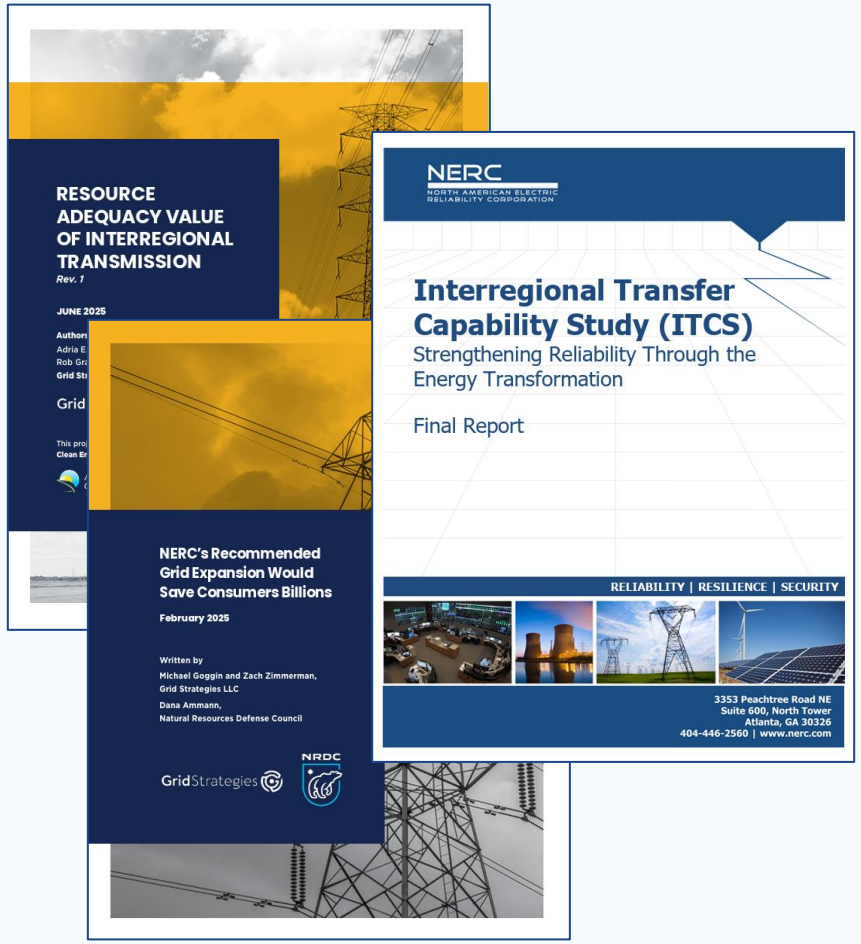
Interregional Transmission Assumptions

Interregional transmission helps to alleviate capacity adequacy concerns, especially during times of grid stress.

One of the many benefits of interregional transmission is the ability to move power between regions during times of grid stress. The availability of imports is primarily due to net load diversity among regions due to timing differences in peak demand and generation unavailability, particularly during severe weather events. Weather patterns and extreme grid events do not impact all regions equally, so there is often spare capacity in a neighboring region that could be shared during times of need. As a result, this benefit will largely persist even if reserve margins in neighboring regions are lower going forward. This phenomenon is well documented in several studies.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores the historical role of "non-firm" imports, which are available during extreme events. For example, MISO imported over 13 GW during Winter Storm Uri, of which 5 GW was in turn exported to SPP, imports that literally kept the lights on in those regions.

Sharing of power can only occur, of course, if enough interregional transmission exists to move the available power. NERC acknowledged this in their 2024 Interregional Transfer Capability Study (ITCS) where they measured the amount of interregional transmission capacity that should be added to each region to help support energy adequacy. The ITCS analysis looks at peak grid stress days for each region and determines if excess capacity is likely to be available in neighboring regions during those same hours. It then suggests interregional transmission capacity be added to move that excess generation.



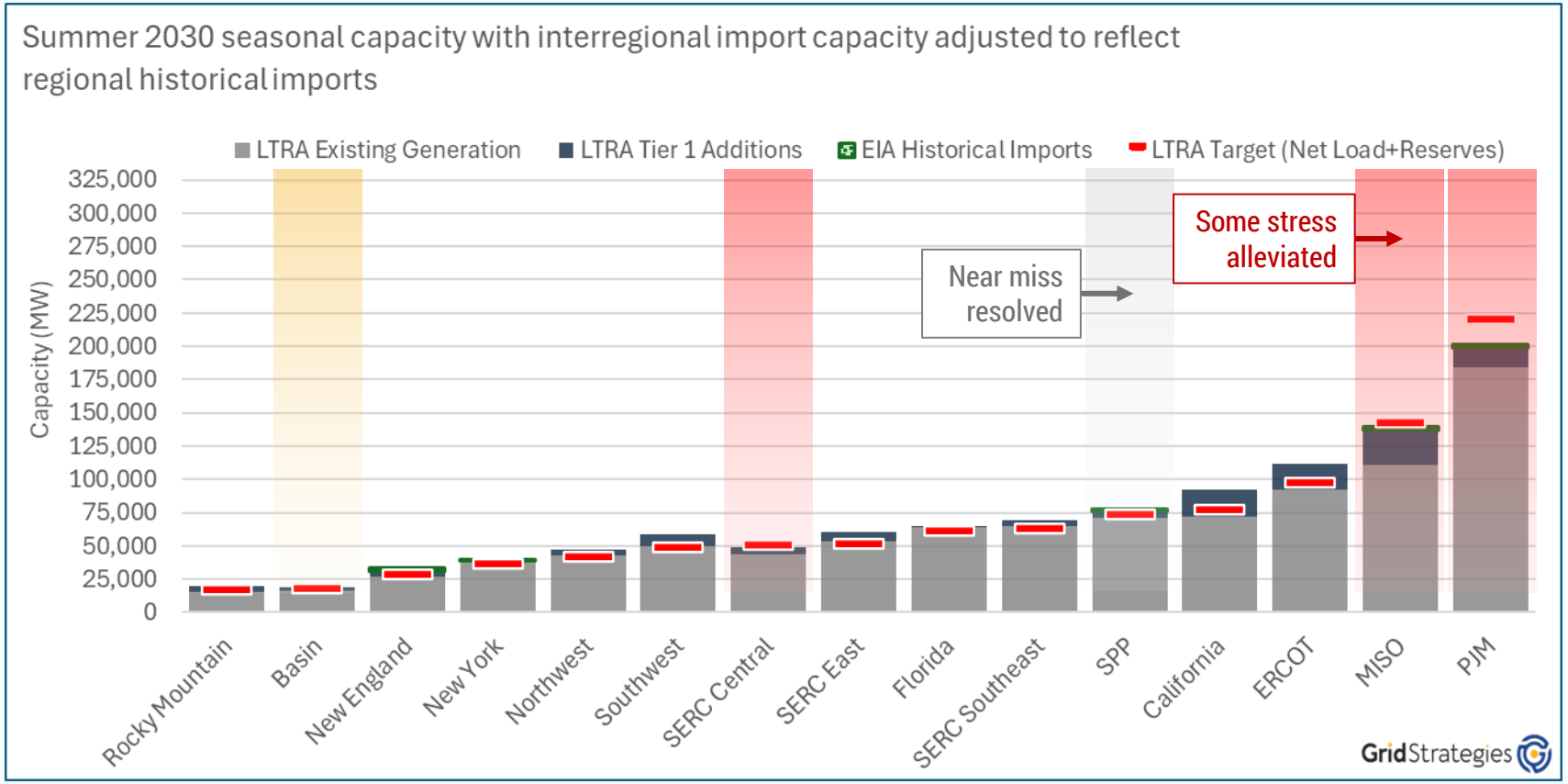
Source | NERC "Interregional Transfer Capability Study" (2024); Goggin, M., Zimmerman, Z., Amman, D., "NERC's Recommended Grid Expansion would Save Consumers Billions" (2025); Brooks, A., Silverstein, A., Gramlich, R., "The Resource Adequacy Value of Interregional Transmission" (2025)

The LTRA only counts firm imports, omitting non-firm imports. Some regional stress is alleviated when combining the LTRA capacity assumptions with historical non-firm import availability.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores non-firm imports over interregional transmission lines that have been available during historical grid stress events.

Hourly regional import and export data collected by the U.S. Energy Information Administration (EIA) confirm regions import significantly more during periods of peak demand than the LTRA assumes.

The inclusion of non-firm imports that are historically available during extreme events helps further alleviate resource inadequacy.



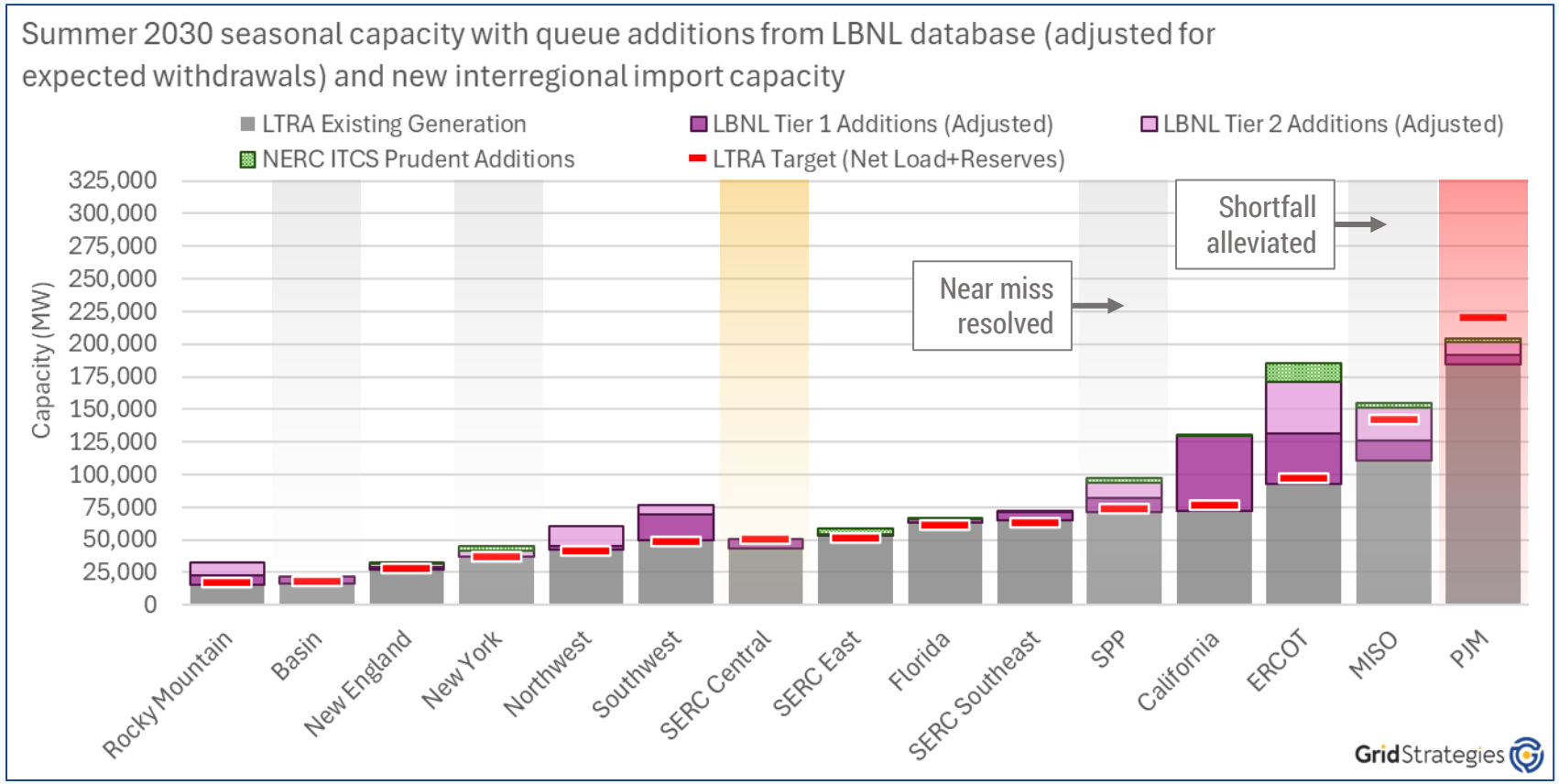
SOURCE | NERC "LTRA" (Jan. 2026); NERC "ES&D" (Jan. 2026); U.S. EIA "About the EIA-930 data" (accessed Feb. 2026)

The combination of NERC-identified increased transfer capability and reasonable resource assumptions from the interconnection queues provides even more security to avoid shortfalls.

The combination of interregional transmission additions suggested by NERC's ITCS and reasonable generation additions using LBNL queue data would provide regions with additional capacity to weather seasonal grid stress events.

The addition of new NERC-identified transfer capability would likely resolve many of the identified seasonal capacity and energy shortfalls.

All transmission takes a long time to develop, but this is especially true for interregional transmission. Unfortunately, the NERC-identified interregional transfer capability additions are unlikely to be built by 2030 under the status quo. Legislative and regulatory action taken now could accelerate the construction of these prudent additions.



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Demand Assumptions

The load growth in the LTRA is based on utility projections that, in some cases, are based on overstated assumptions.

NERC compiled the LTRA load growth forecast by rolling up projections from utilities and regional grid operators. Large load forecasts are uncertain and could overstate load growth for several reasons.

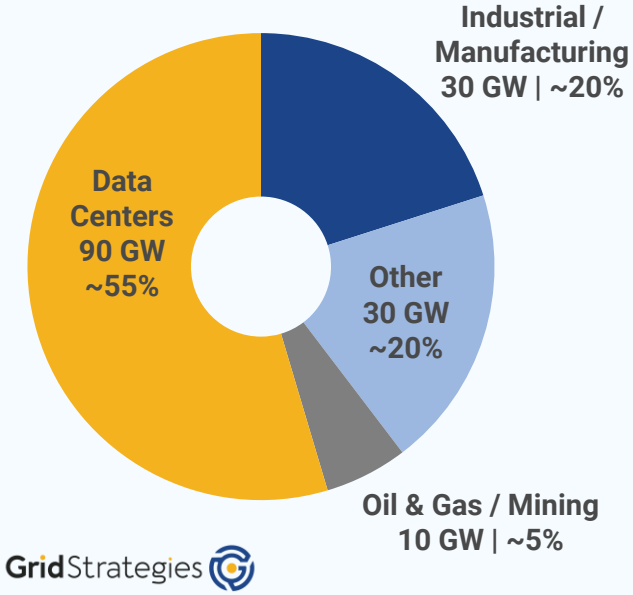
Reliance on customer data: Large load forecasts rely primarily on customer-supplied information.

- Data centers, in particular, are constrained by global supply chains. There is no clear method for individual load forecasts to account for how supply chain constraints will affect specific projects.
- Load forecasts lack visibility into customers' overall business plans. There may be "double counting" as data center operators develop more sites as options than they intend to build. The LTRA includes all loads with "development commitments necessary to drive grid planning studies." In contrast, the LTRA only counts generators that have completed all planning studies and signed an interconnection agreement.
- Many regulated utilities have an incentive to overstate load growth and interconnection success rates to justify additional rate-based investments in generation and other infrastructure.

Time lags: Producing and compiling load growth projections occurs months before the LTRA is released. Mounting delays in large load interconnection and policy changes appear to have slowed load growth since their compilation.

- Load interconnection queue backlogs and long lead times for power transformers and circuit breakers needed for interconnection are likely to delay commercial operation of many large load projects.
- As outlined in the following slides, new large loads from data centers, cryptocurrency mining, and hydrogen electrolysis could each face headwinds that are not fully accounted for in the LTRA.
- Recent policy changes are reducing load growth, such as the recent termination or restriction of federal tax credits for electric vehicles, heat pumps, hydrogen electrolysis, and advanced manufacturing.

Drivers of Load Growth (2025 – 2030)



Load flexibility: Regulations and utility tariffs are beginning to require some large loads to provide demand response or backup generation during periods of peak demand. ERCOT's load forecast includes substantial demand response for crypto mining facilities and assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%.

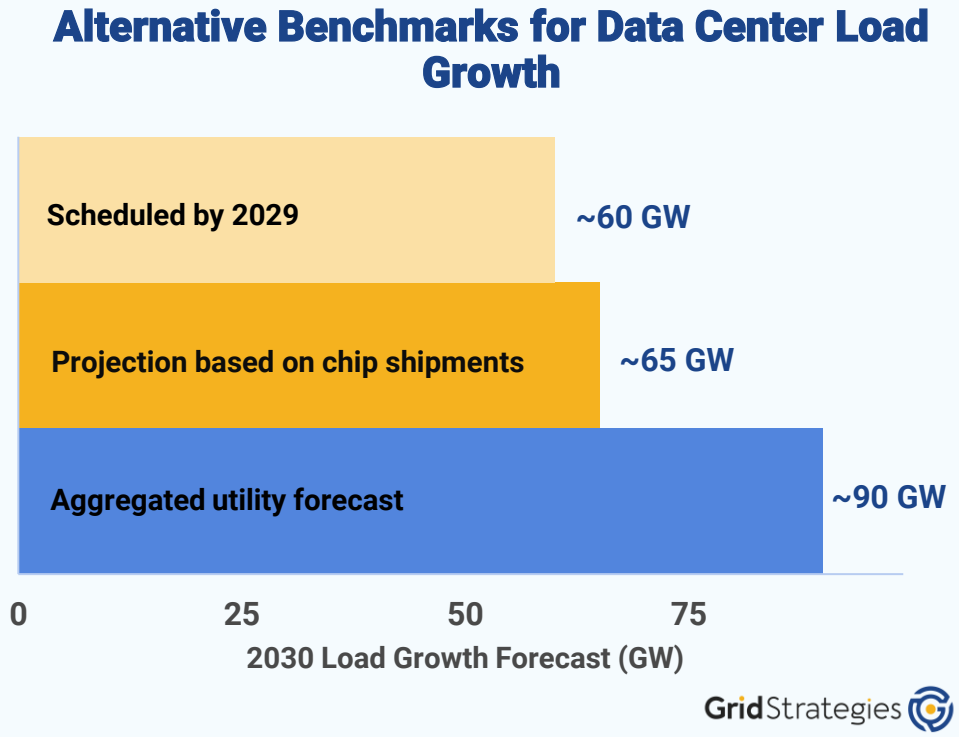
GridStrategies

SOURCE | Wilson, J., et al. "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers" (Nov. 2025)

Assumed data center load

The LTRA reasonably states that, “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.” However, the growth of data centers and their contribution to peak demand may be overstated due to:

- **Supply chain shortages of chips and other key inputs.** TD Cowen estimated that due to chip limitations, U.S. data center growth would be limited to 65 GW (orange bar), about two-thirds of the data center growth assumed for the U.S. alone in the LTRA (blue).
- **Financial constraints.** Wall Street analysts have expressed concerns that expected revenues are insufficient to sustain the overall industry trajectory for AI data center investment.
- **Load flexibility.** Data centers may be able to use local generation and storage resources to reduce or eliminate their on-peak demand for grid power. Additionally, some types of data centers may opt to curtail their demand during peak periods without local supply. Curtailment activities such as these are unlikely to appear in utility forecasts of expected load. These practices may drive up annual energy use.



GridStrategies

SOURCE | TD Cowen, Data Centers, Generative AI, & Power Constraints: The Path Forward (May 2024); Bain & Company, “$2 trillion in new revenue needed to fund AI’s scaling trend” (Sept. 2025); Wilson, J., et al. (2025)

Assumed cryptocurrency mining load

Cryptocurrency mining accounts for about 7 GW or 15% of ERCOT's projected large load growth through 2030, though it is likely lower in other regions.

However, cryptocurrency mining data centers are understood to be more speculative than other data center types. Cryptocurrency mining facilities are highly modular and can be readily moved to different sites, even after they have been installed and put into service at a site. Unlike some types of data centers, they do not face major siting constraints due to concerns about latency or access to fiber networks. These factors increase the likelihood of "double counting."

In ERCOT, cryptocurrency mines routinely use demand response or price-sensitive demand bids to curtail demand during peak periods. If properly incentivized to do so, their contribution to peak demand can be reduced or eliminated.

Assumed Hydrogen Electrolyzer Load

Most hydrogen production load is forecast in ERCOT, where planned electrolyzers account for about 8-9 GW or 20% of ERCOT's projected large load growth through 2030. NYISO's load forecast used to include substantial hydrogen production, but it has been adjusted downward. Only a few other load forecasts mention hydrogen production, and at much lower volumes than in ERCOT. According to EIA data, the U.S. had only 116 MW of hydrogen electrolyzers in operation in 2024.

ERCOT's forecast may not reflect a full market response to congressional action to tighten the timeframe for projects to qualify for the Section 45V Clean Hydrogen Production Credit. The credit is now only available for facilities that begin construction by the end of 2027 instead of 2032.

The operation of planned electrolyzers is also difficult to forecast, but they are unlikely to fully contribute to peak load for two reasons:

- The tax credit depends on the carbon-intensity of electricity consumption. This will drive electrolyzers operation to hours with high renewable generation, which are unlikely to be periods of peak net load.
- Regardless of the tax credit, electrolyzers will tend not to operate on-peak because the electricity would be too expensive.

SOURCE | U.S. EIA "Electrolyzers are a small but growing source of U.S. hydrogen production" (2024)

Load flexibility can reduce the capacity needed for large loads

Nearly all the preceding categories of large loads can use demand response, on-site generation and storage, or price-responsive loads to reduce or eliminate their contribution to peak demand.

The LTRA assessment of ERCOT's planning reserve margin assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%. Through 2035, as load grows by 59 GW, demand response grows by 50 GW. NERC states that it made this assumption because "signed into law in June 2025, Texas Senate Bill 6 directs the Public Utility Commission of Texas 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."

While there is considerable debate about the feasibility for some types of data centers to provide flexibility, ERCOT's requirement shows the potential impact on resource adequacy. Nonetheless, no other load forecasts used to inform the LTRA include similar load flexibility assumptions. As a result, a large share of the projected load growth in the LTRA for other regions could be negated if NERC likewise assumed, as it did for ERCOT, that large loads use some type of flexibility during peak periods. Large loads in these regions could use similar flexibility solutions. For example, Google has signed agreements with utilities to use flexibility to reduce peak load contributions from data centers in Indiana, Nebraska, Arkansas, and the Tennessee Valley Authority footprint (Google 2025).

A recent study estimates 30% of data centers may install flexible capability anyway to curtail during localized transmission system overload or contingency events, as a way to move to the front of lengthy interconnection backlogs by reducing the need for cost- and time-intensive grid upgrades (Thomas 2026). Data centers that are unable to curtail could use behind-the-meter resources during peak periods to reduce or eliminate their reliance on grid power.

SOURCE | Google "How we're making data centers more flexible to benefit power grids" (Aug. 2025); Thomas, M. "Bypassing the Grid: How Data Centers Are Building Their Own Power Plants" (Feb. 2026)

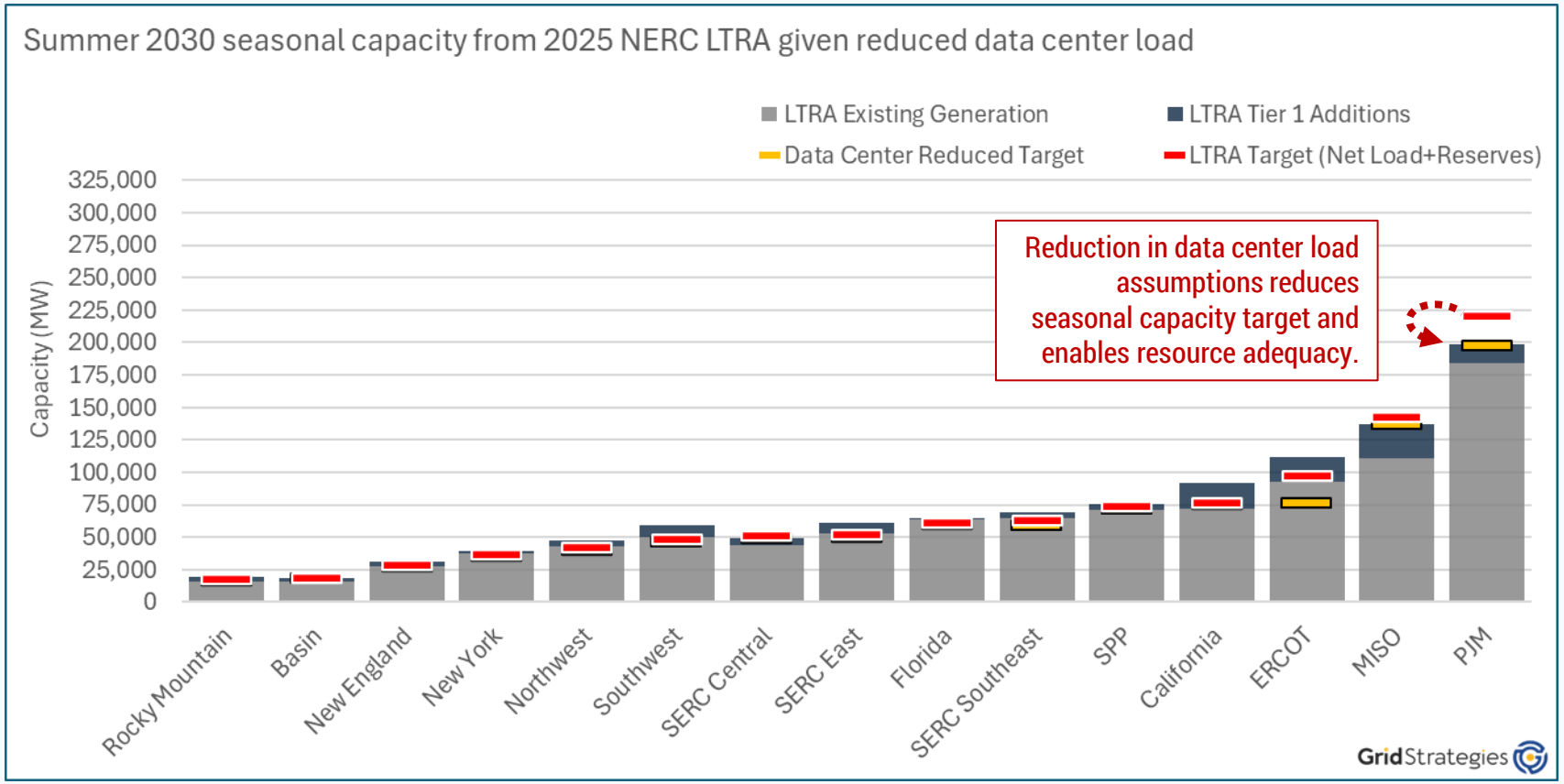
Updating data center load forecasts based on chip-industry forecasts would allow nearly all regions to meet their 2030 target needs

NERC indicates that load growth in several regions is dominated by data centers. To highlight the impacts of uncertainty in data center growth projections in the LTRA, we introduce a scenario which reduces national 2030 data center growth by two-thirds. This reduction is distributed among the regions based on their individual forecasted data center load and is shown as a yellow target in the chart.

A one-third reduction is based on chip industry forecasts and an additional one-third is based on assumed use of on-site generation during peak demand.

Consideration of potential reductions in data center load growth enables all regions to meet their 2030 peak summer load and reserve needs.

Note: If no red target is visible, then the two targets appear to overlap. All regions' net load was reduced.



GridStrategies

SOURCE | NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026)

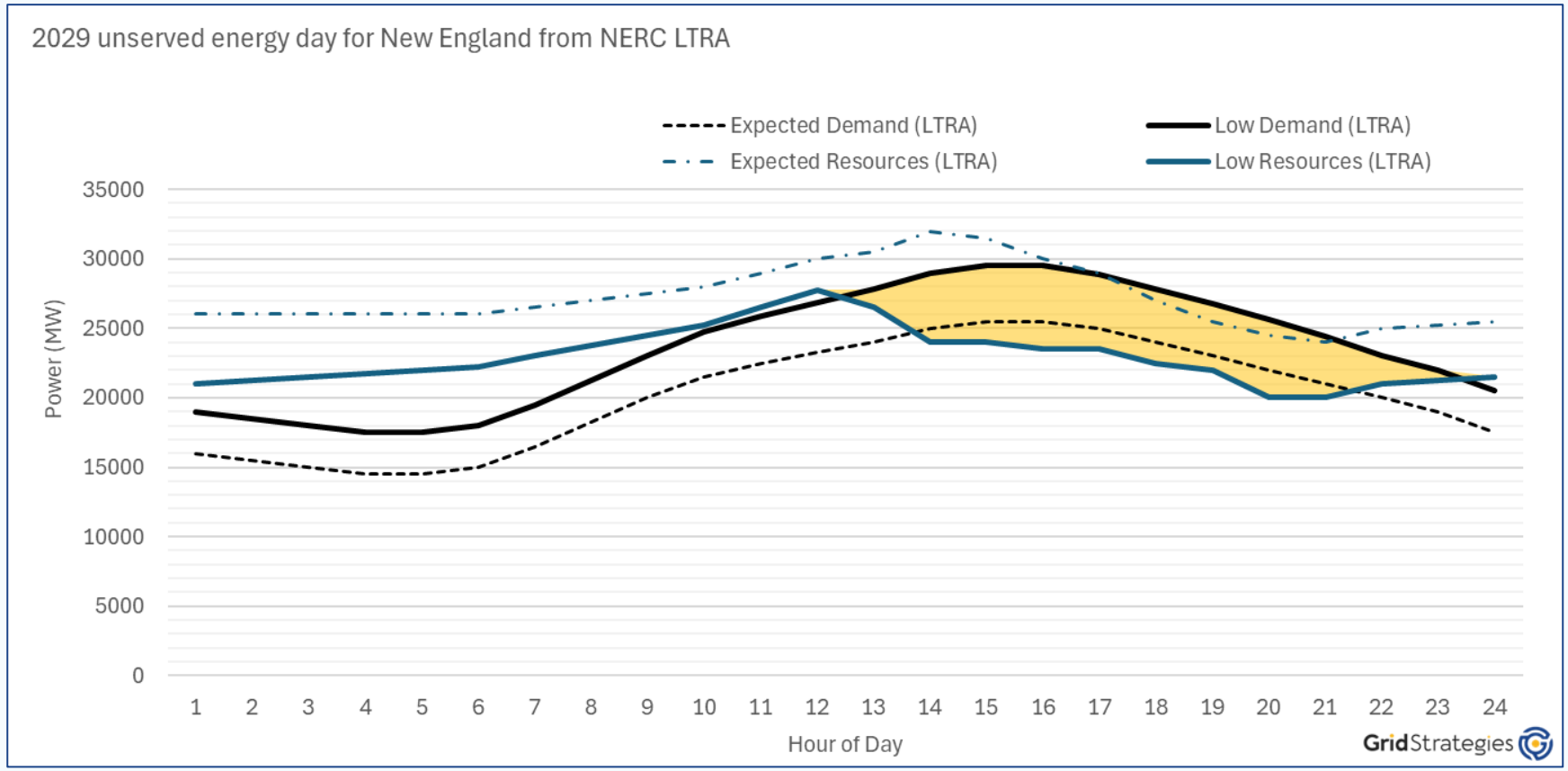
Extreme Event Energy Adequacy

Energy inadequacy risk during extreme events can exist even without seasonal capacity shortfalls. An increase in resource and interregional transfer capability also helps to alleviate extreme event risk.

The risk of energy shortfalls during extreme grid events can exist even without there being a risk of capacity shortfalls when considering only seasonal peak load. It is important to study both capacity and energy adequacy.

For example, NERC found energy shortfalls could occur during extreme heat days in New England,* even though it did not find seasonal capacity shortfalls.

Expected resource production is enough to meet expected demand (dotted lines) on most days, but sensitivity testing shows that the combination of lower-than-expected resources and high demand (solid lines) could result in energy shortfalls (yellow area). Energy shortfalls are often referred to as "unserved energy" or energy inadequacy.



*This figure is a recreation of the extreme event energy analysis shown in the LTRA for New England. We did not independently reproduce this analysis.

GridStrategies

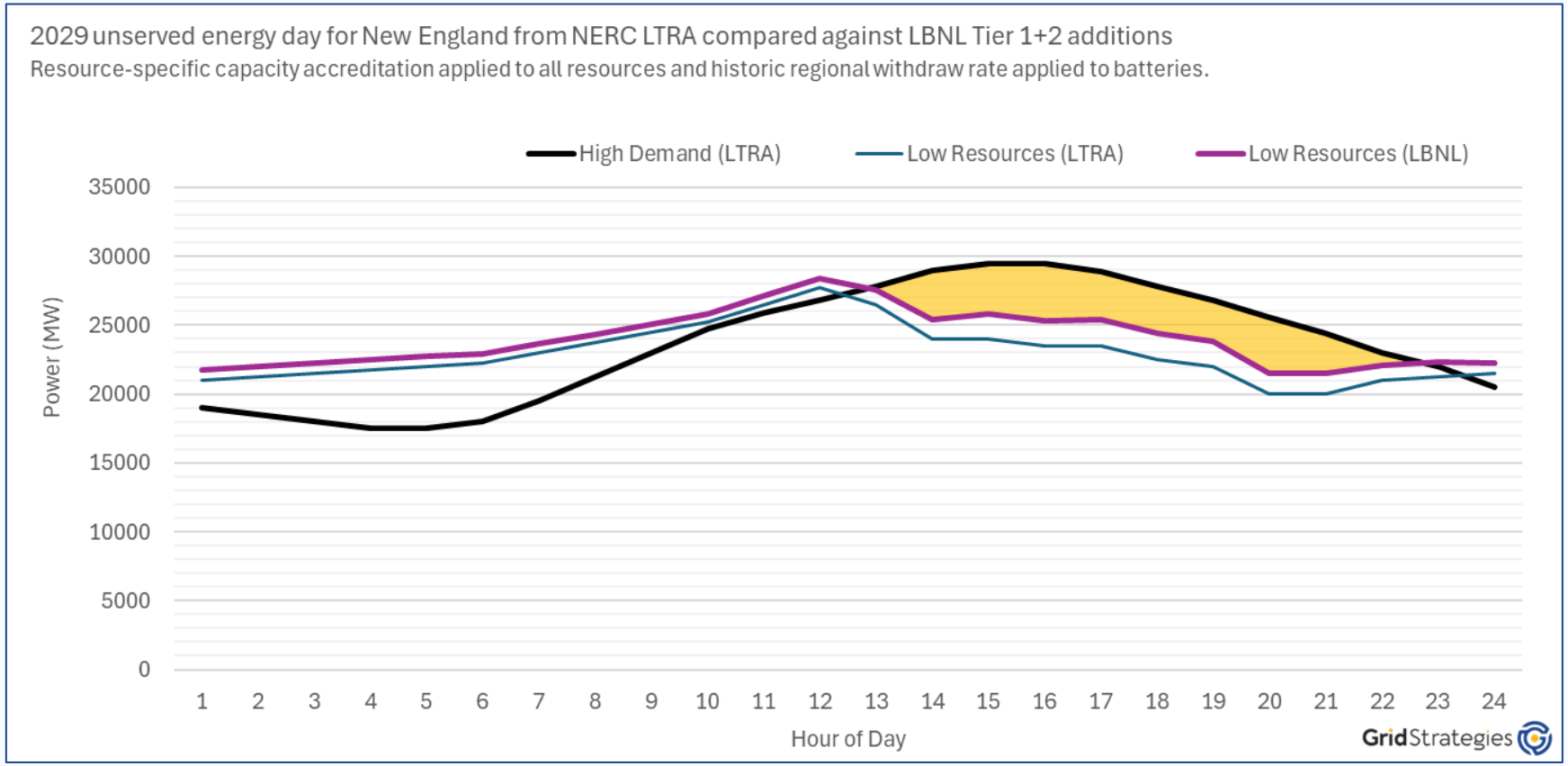
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Using LBNL resource assumptions for New England greatly reduces unserved energy risk during peak load days.

LBNL data records more solar, offshore wind, and storage resources than the NERC data.* Lower-than expected production from the LBNL-identified resource mix (purple line) better matches the times of high demand (black) than the NERC-identified resource mix (blue).

Given accredited, likely-to-connect Tier 1 and 2 resource capacity from LBNL, the amount of potential unserved energy on peak summer days in New England is reduced by nearly 40% of that calculated using NERC data. If capacity had not been reduced by expected withdrawals, the unserved energy shown here would be completely resolved.

Diverse resource mixes—especially those matched to the load profiles of the region—provide major benefits to withstand extreme grid events.



*See the Methodology section for more details.

GridStrategies

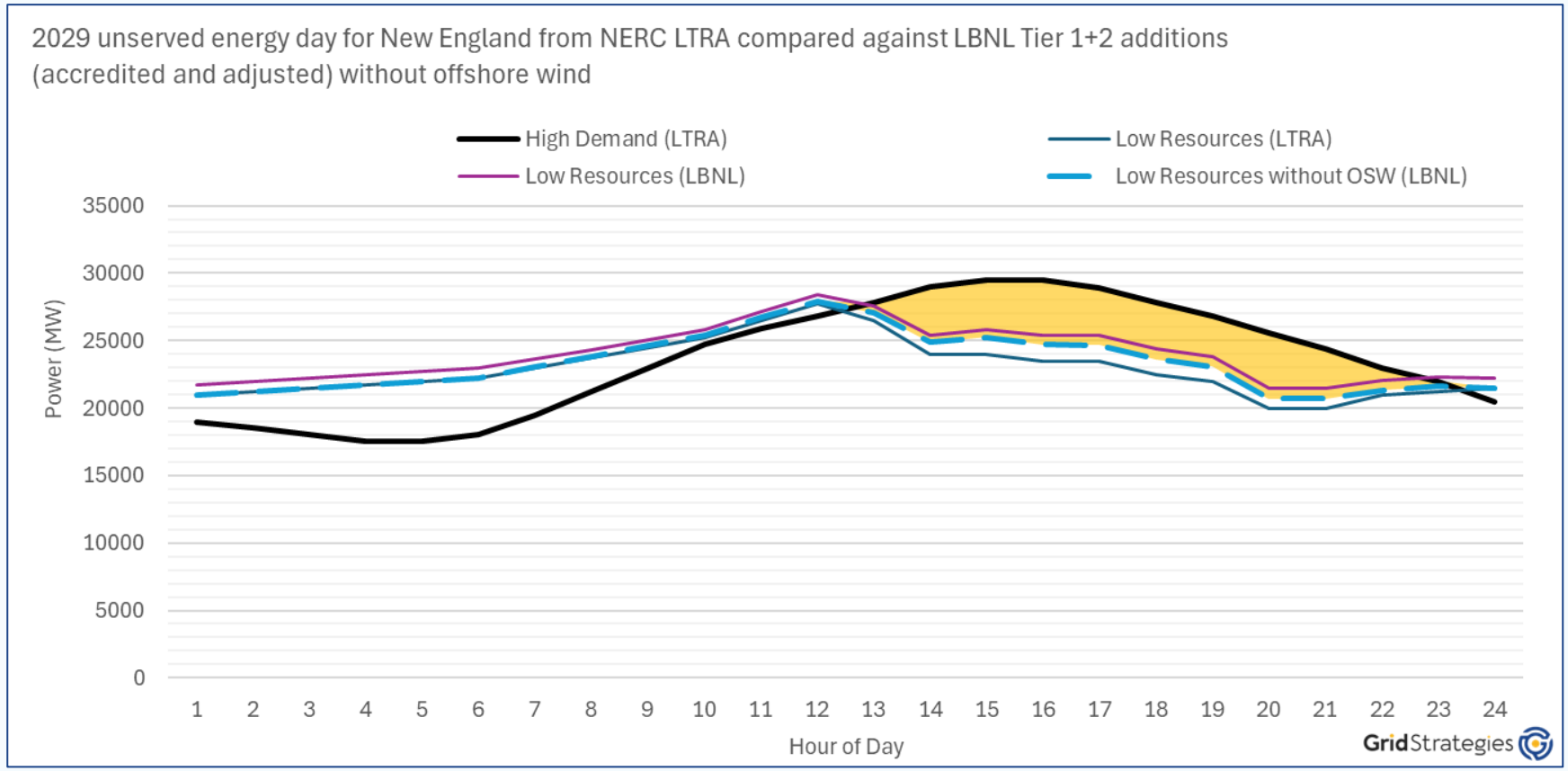
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

As with seasonal capacity adequacy, permitting and/or construction delays of resources with executed IAs are likely to exacerbate energy inadequacy risk during extreme grid events.

Delays of resources progressing through the queues or with executed IAs, whatever the cause, will exacerbate the risk of unserved energy during extreme grid events. Currently, offshore wind is facing additional permitting and construction hurdles. This is especially noteworthy for New England, where strong afternoon offshore wind output could directly reduce unserved energy risk during peak load hours.

Near-term unserved energy risk increases substantially given the delay or cancellation of planned offshore wind generation.

Given the low production of a resource mix without offshore wind (shown as the blue dotted line), the unserved energy risk is only reduced by 20% instead of 40% of that calculated in the LTRA.



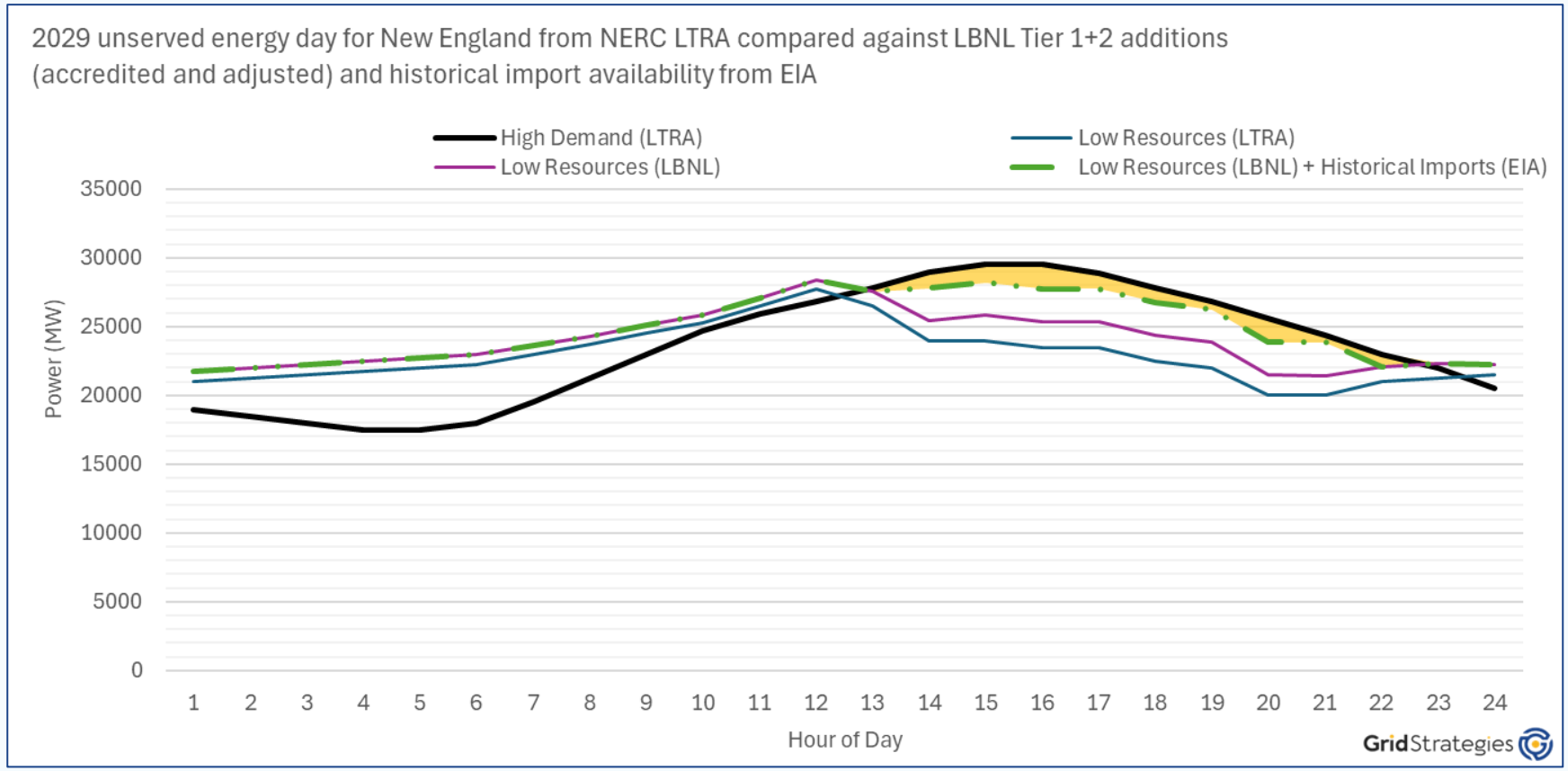
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Interregional transmission designed to move power between regions during times of grid stress further reduces unserved energy risk.

As explained in slides 15-17, NERC only includes firm imports in its seasonal capacity or energy adequacy analysis. This ignores the likelihood of additional "non-firm" imports which are historically available to regions during extreme events. Non-firm imports are those which are not contracted for use during normal operations, but that neighboring regions can export to regions experiencing heightened stress.

Adding the imports which have been historically available to New England during extreme events further reduces expected unserved energy.

The combination of likely-to-connect generation from the interconnection queues and historically available non-firm import data nearly eliminates the unserved energy risk calculated using the LTRA assumptions.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

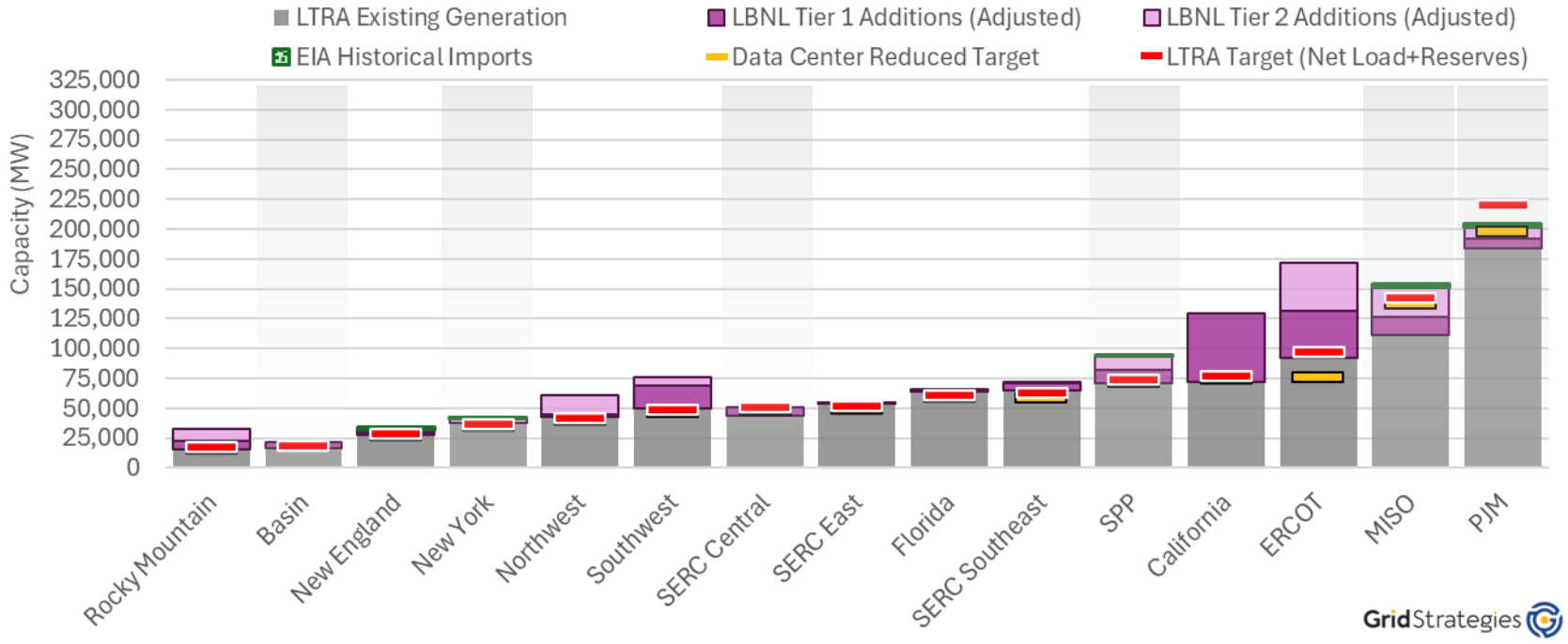
Conclusions and Solutions

In this analysis, we considered different assumptions for generation resource, interregional transmission, and demand than the LTRA. The combination of all three suggest all regions could be resource adequate.

The regional seasonal resource adequacy risks identified in the 2025 NERC LTRA are all resolved when evaluated under different input assumptions:

- Including generation that is actively working through the interconnection queues in each region (Tiers 1 & 2)
  - Discounting all generation nameplate capacity by the resource and region-specific accreditation methods
  - Discounting generation queue data by historic regional and phase-specific withdraw rates
- Consideration of historic non-firm imports during extreme events
  - Including increased interregional transfer capability capacity (albeit low likelihood of 2030 in-service date)
- Reduced data center load to account for microchip industry supply chain constraints and generation flexibility

Summer 2030 seasonal capacity with queue additions from LBNL database (adjusted for expected withdrawals), interregional import capacity (adjusted for historical imports), and reduced data center load



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

While reduced risk is likely given different assumptions, these results should not be taken for granted. Enacting existing solutions is needed to stave off future reliability risk.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Methodology

The NERC LTRA assesses each region's ability to meet both its future capacity and energy adequacy needs.

NERC's LTRA importantly captures potential reliability issues for a snapshot in time. Risk is defined by tightening reserve margins—the difference between electricity demand and available supply.

In its 2025 version, NERC identified several regions* as either **High** or **Elevated** risk of not being able to meet their future capacity and energy needs.

Seasonal capacity shortfall risk: MISO, PJM, and SERC-Central (with SPP and Basin on the margin)

Extreme event energy shortfall risk: MISO, PJM, New England, New York, SERC-East, Basin, Northwest, and ERCOT

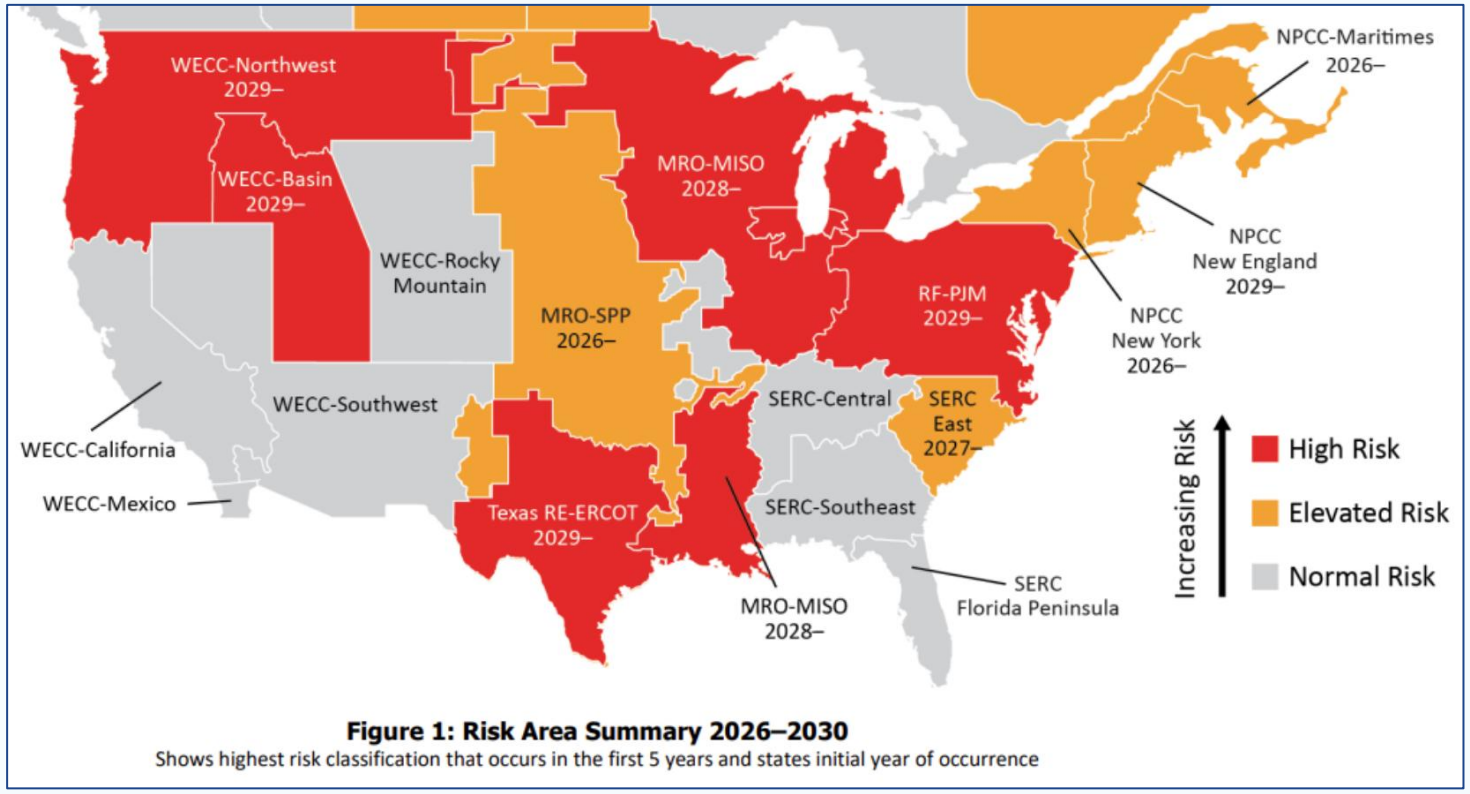


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

*NERC did not mark SERC-Central as elevated risk despite showing large seasonal shortfalls while SPP was marked as elevated risk despite having neither seasonal capacity shortalls nor extreme event energy shortfalls.

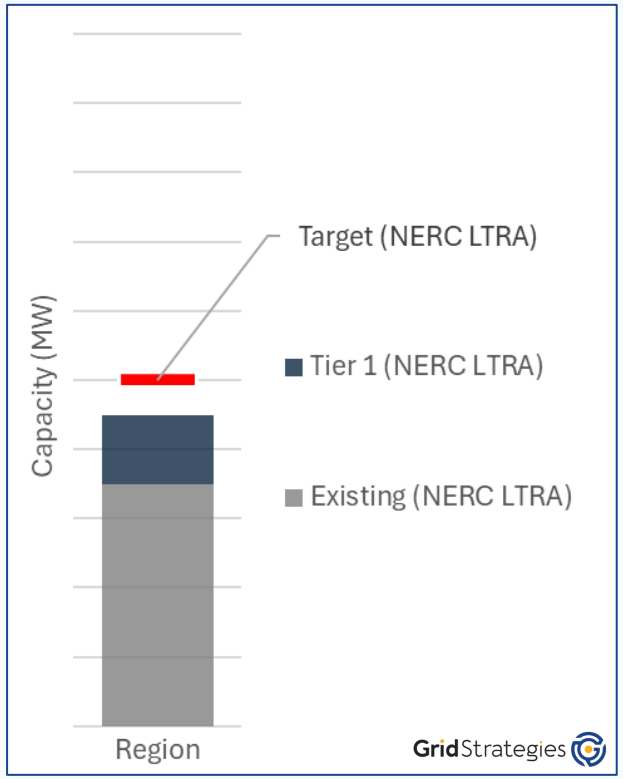
GridStrategies

SOURCE | NERC "2025 LTRA" (2026)

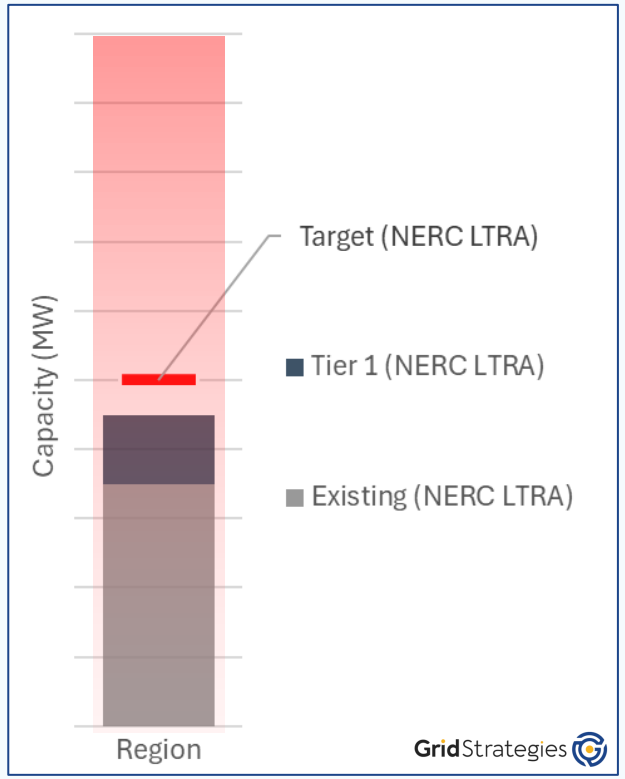
Illustrative walkthrough of seasonal capacity slides

Bar charts showing the existing (light grey) and future (dark blue) resource capacity in each region using NERC LTRA data. The target capacity (red line) is also shown. These charts were created by Grid Strategies using NERC data.

A red highlight is used to signify a shortfall between the existing + future resource capacity and the needed target to meet future load and reserves. A yellow highlight would be used to signify a "near miss."



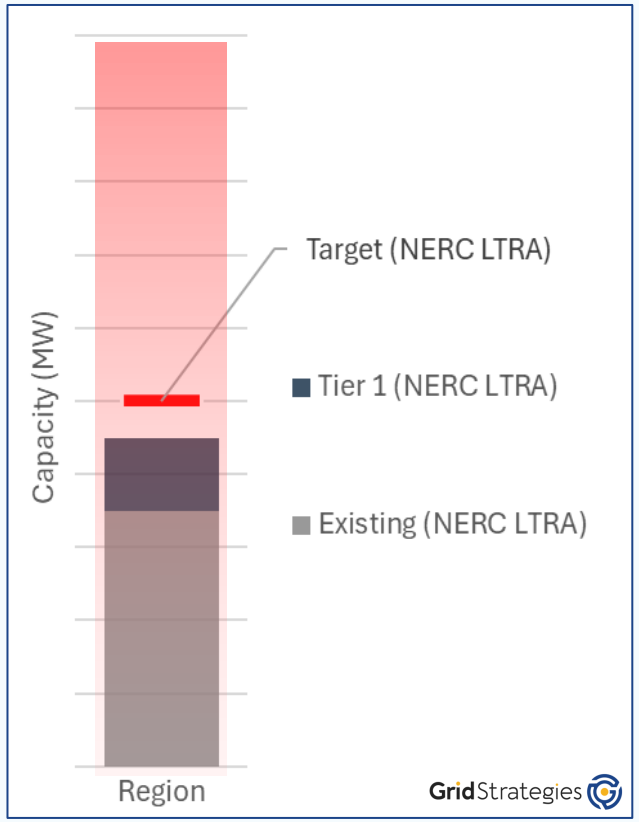
Highlight important features of chart



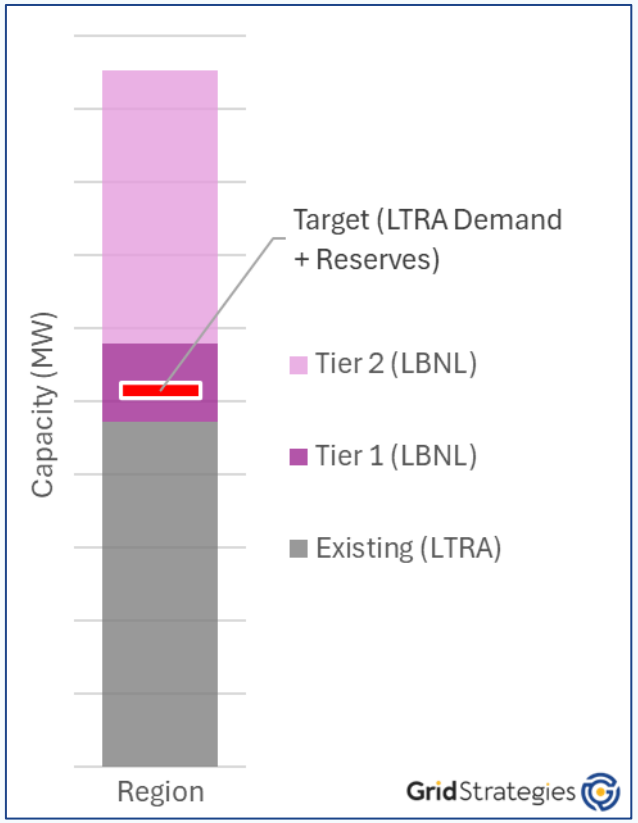
Illustrative walkthrough of seasonal capacity slides

Replace the NERC LTRA resource capacity data with accredited LBNL interconnection queue data (purple) for comparison. Existing and target data is from LTRA and remains unchanged unless specified.

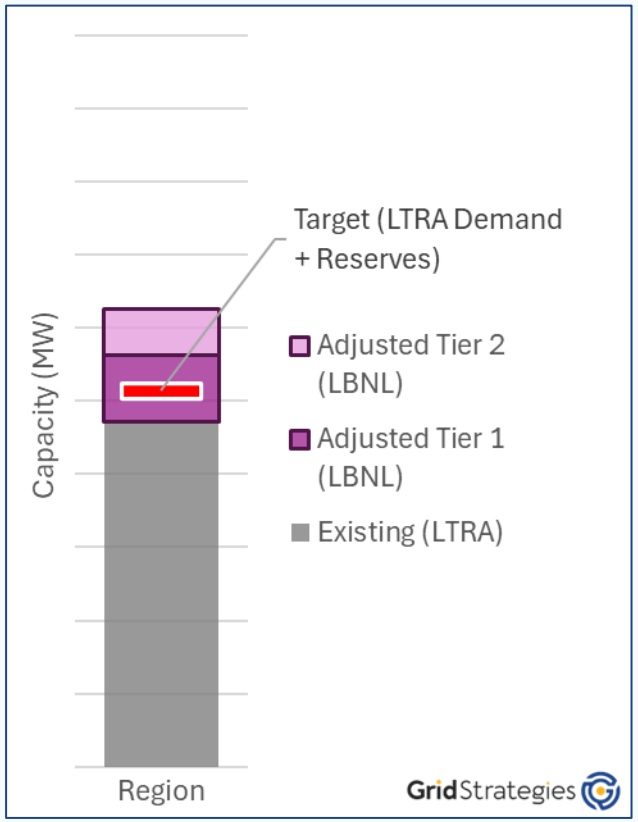
To avoid overcounting queue generation, the LBNL data is discounted based on regional- and study phase-specific withdraw rates.



Replace NERC data with resource-accredited LBNL data



Reduce LBNL data based on expected withdraws



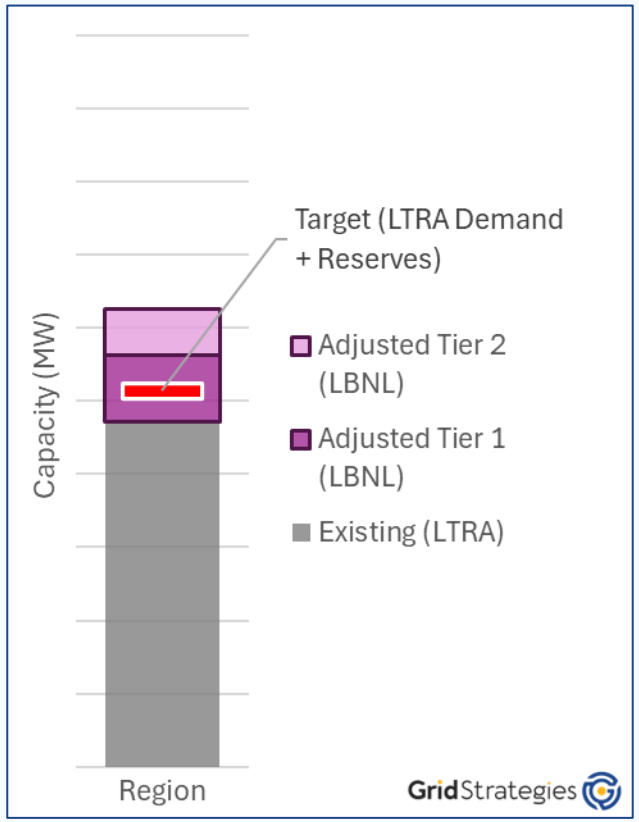
Note red highlight is removed because adequacy has been achieved

GridStrategies

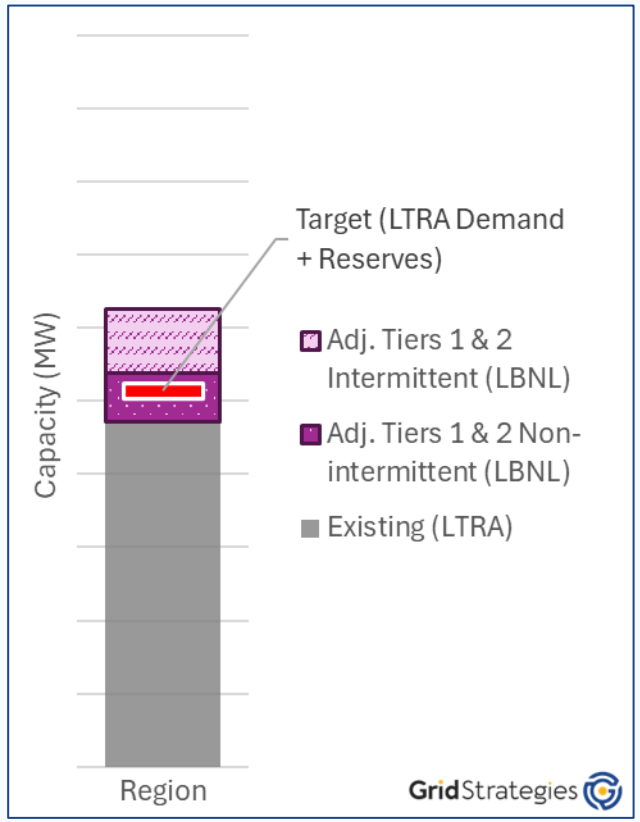
Illustrative walkthrough of seasonal capacity slides

Analyze the LBNL resource data to gain insight into future capacity risk. Purple is still used for LBNL data while different bar borders or pattern are used to indicate interesting features of the data.

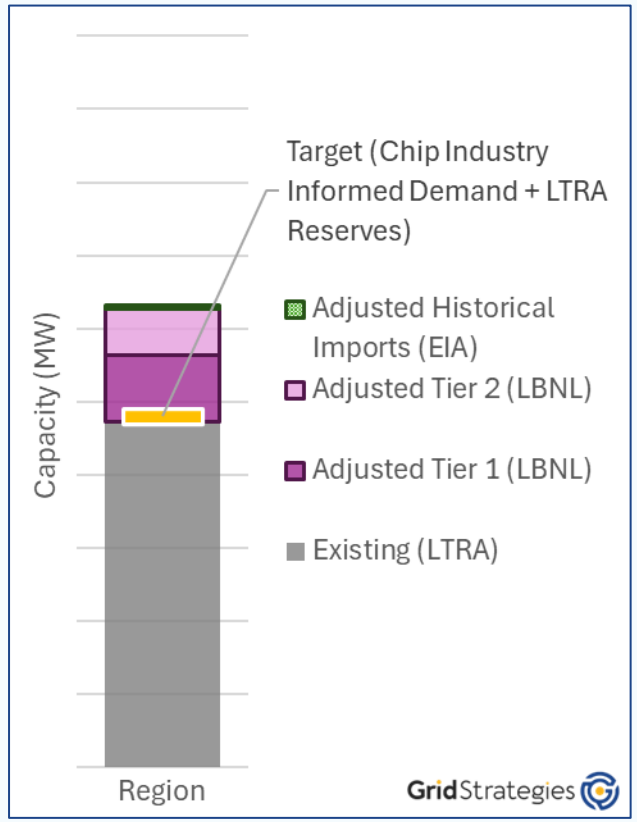
Interregional transfer capability data is adjusted using EIA data to better illustrate available capacity. In some cases, the expected load is changed to match demand forecasts from other sources.



Look at different features of LBNL data



Continue to add more data for analysis



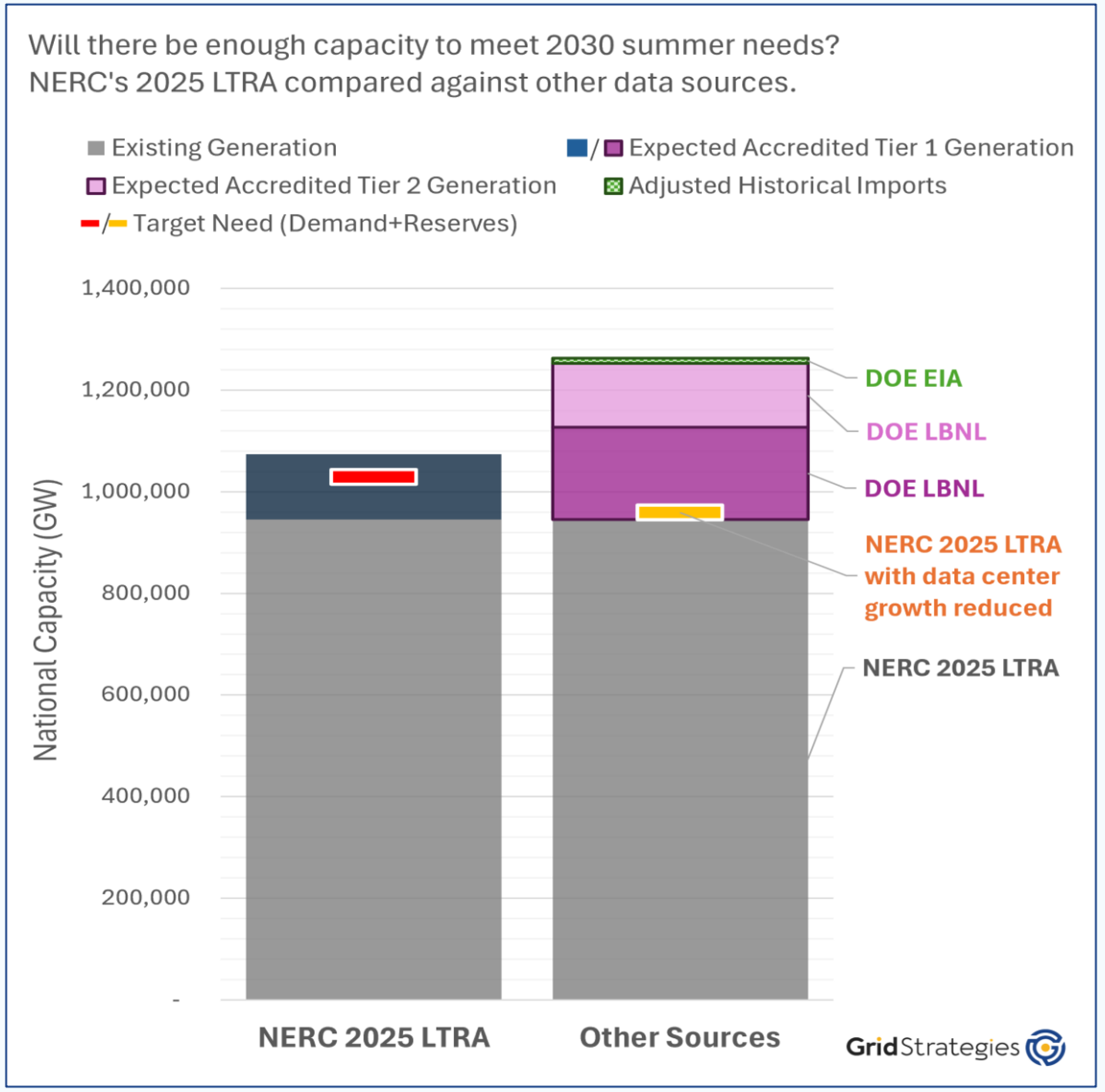
Summary slide of seasonal capacity differences in 2030

On Slide 6, the comparison of NERC 2025 LTRA analysis against our analysis using other sources is meant as an illustrative comparison of the national risk given the use of different credible data sources.

The NERC 2025 LTRA bar was made by summing the forecasted 2030 summer load + reserves (target), existing generation, and Tier 1 data for each region directly from the NERC data.

The target value shown in "Other Sources" was created by applying a one third derate to known data center load growth in all regions. The one-third derate factor is the ratio of estimated data center growth in 2030 from chip shipments to the estimated growth from utility roll-ups as used by LTRA (Wilson, J., et al. 2025). Another one-third derate factor is from the assumption that many data centers are likely to use some form of on-site generation or storage to curtail their peak demand (Thomas, M., 2026). The known data center load growth is from Grid Strategies analysis of total system load growth that is attributable to data centers (Wilson, J., et al. 2025). The impact of this data center growth reduction scenario on individual regions is shown in slide 24.

The generation resources shown in "Other Sources" is the sum of resources available in the LBNL dataset that are reasonably expected to connect by 2030. Adjusted historical imports represent the non-firm imports that have been available during grid stress events from the Energy Information Administration. More detail on the other sources data is provided in subsequent slides.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026); Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Analysis using LBNL data: Regional assessment areas

The DOE's Lawrence Berkeley National Laboratory collects data from the generation interconnection queues for seven ISOs / RTOs and 49 non-ISO balancing areas (including utilities and Power Marketing Administrations), representing roughly 97% of currently installed U.S. generating capacity. This data is compiled annually with help from Interconnection.fyi and is posted for public view at emp.lbl.gov/queues. The 2025 dataset includes data through the end of 2024.

The 56 entities in the LBNL database were mapped to the NERC LTRA assessment areas by geography (maps to the right). The non-RTO utilities were mapped as follows:

WECC California
- LADWP
- SMUD
- WAPA-SN

WECC Rocky Mtn
- CLPT
- BHCT
- CSU
- PacifiCorp
- PRPA
- PSCo
- TSGT
- WAPA-RM

WECC Northwest
- Avista
- BHP
- BPA
- CPUD
- GrantPUD
- MPC
- NWMT
- PGE
- PSE
- TPU
- WAPA-IS

WECC Basin
- IdahoPower

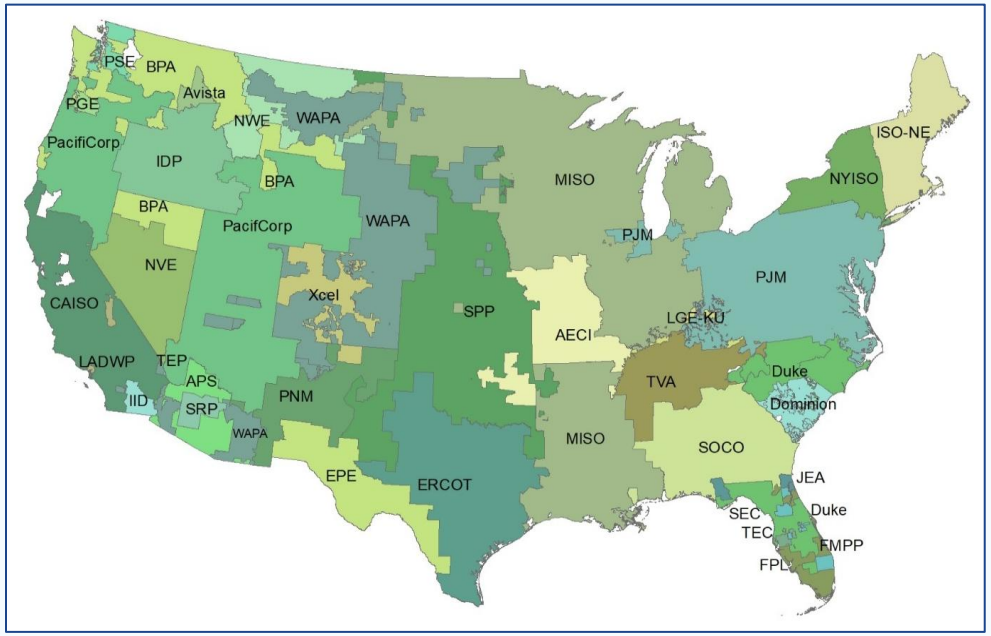
WECC Southwest
- APS
- EPE
- IID
- N-C
- NVE
- PNM
- SRP_ANPP
- SRP
- SRP_Gila
- SRP_PV-PC
- SRP_SWV
- TEP
- WAPA-DSW
- WAPA-MPP

SERC Central
- AEC
- LGE-KU
- TVA

SERC Southeast
- GTC
- SOCO

SERC Florida
- OUC
- TEC
- Duke (FL)

SERC East
- Dominion
- S-C
- Duke (non-FL)



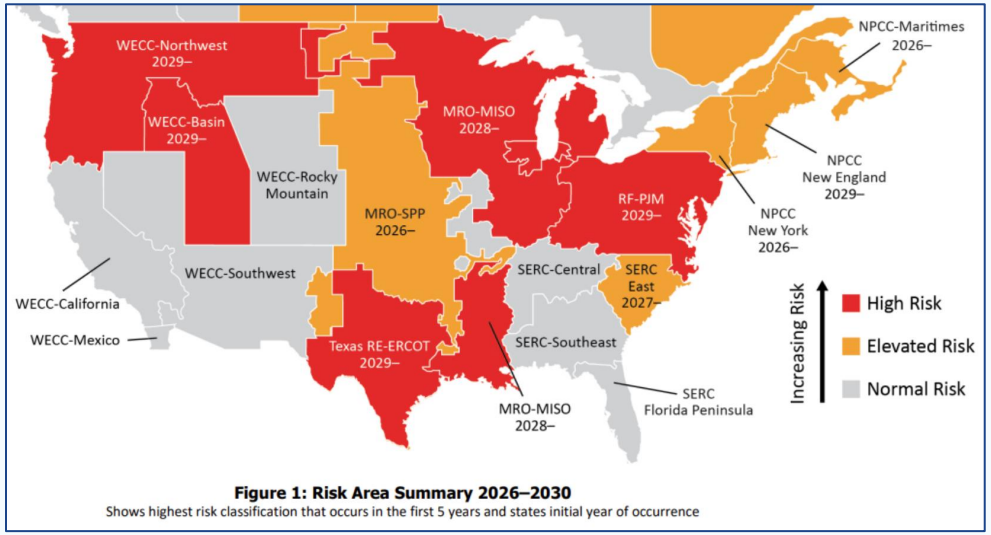


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis of LBNL data: Generation tier status

LBNL interconnection data is organized by its queue status and study phase in the interconnection queues. Queue status refers to if the facility is completed, withdrawn, or actively progressing through the queues.

NERC organizes in-development generation resources by Tiers, where:

- Tier 1 are resources with executed interconnection agreements
- Tier 2 are any resource that is in the study process, and
- Tier 3 are those that have submitted interconnection requests but are not yet under study.

The cross-walk between LBNL's "Queue Status" and "IA Status Clean" fields and the NERC Tiers used in this analysis are shown to the right. Interconnection requests marked as Active in the Queue Status are organized into Tiers based on their IA Status.

Resources considered in to be in advanced Tier 2 status were those with either "IA Pending" or "Facility Study" status in the LBNL data. Suspended interconnection requests are considered Tier 2 because they have already completed some study phases but have paused their continuation of progress. Requests that un-pause often enter at the same study stage. Requests of Unknown or N/A status are considered Tier 3 because their existence in the database indicates an interconnection request has been made, but whether studies have begun cannot be said for sure.

LBNL Queue Status	NERC Tier
Active	(see IA Status)
Withdrawn	Cancelled
Operational	Operational
Suspended	Tier 2
Unknown	Tier 3

LBNL IA Status Clean	NERC Tier
Withdrawn	Cancelled
Operational	Operational
IA Executed	Tier 1
Construction	Tier 1
IA Pending	Tier 2
Facility Study	Tier 2
Cluster Study	Tier 2
System Impact Study	Tier 2
Feasibility Study	Tier 2
Combined	Tier 2
In Progress (unknown study)	Tier 2
Suspended	Tier 2
Not Started	Tier 3
N/A	Tier 3

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Expected withdraw rates

To reduce the likelihood of overcounting generation resources that may not interconnect, we reduced all Tier 1 and 2 resource data in the LBNL queue dataset given region- and status-specific historic withdraw rates.

LBNL publishes the completion rates (as of 2024) of all resources in the regional queues that entered the queue between 2000 and 2019. The withdraw rates vary regionally between 64% and 85%. LBNL also provides information about the queue study phase that projects were in when they withdrew. In general, fewer projects withdraw once they reach advanced stages of the interconnection queue process.

Applying the regional withdraw rates to all generation without regard for its queue location would overly discount generation in Tier 1 and advanced Tier 2 status. Instead, we adjust the amount of generation that is expected to withdraw from each Tier separately. See illustrative figure to the bottom right.

We first calculate the total amount of expected regional withdraws by applying the appropriate withdraw rate to the sum of all Tiers 1, 2, and 3 generation in each region's queue. We assume that 15% of generation in Tier 1 status will withdraw, equivalent to the share of withdrawn requests between 2019 – 2023 in the IA executed phase from LBNL's analysis. Because no generation in Tier 3 is expected to interconnect by 2030, we assume 100% of Tier 3 generation withdraws for every region. The difference between the total amount of expected regional withdraws and that which is assumed to withdraw from Tiers 1 and 3 in each region is applied to the Tier 2 data.

LBNL: Historical completion by region for requests submitted 2000-2019 (as of 2024)

Region	Active	Operational	Withdrawn
CAISO	14%	9%	77%
ERCOT	14%	22%	64%
ISO-NE	8%	18%	74%
MISO	9%	15%	76%
NYISO	7%	8%	85%
PJM	8%	14%	77%
SPP	9%	14%	76%
Southeast	5%	9%	85%
West	13%	9%	79%

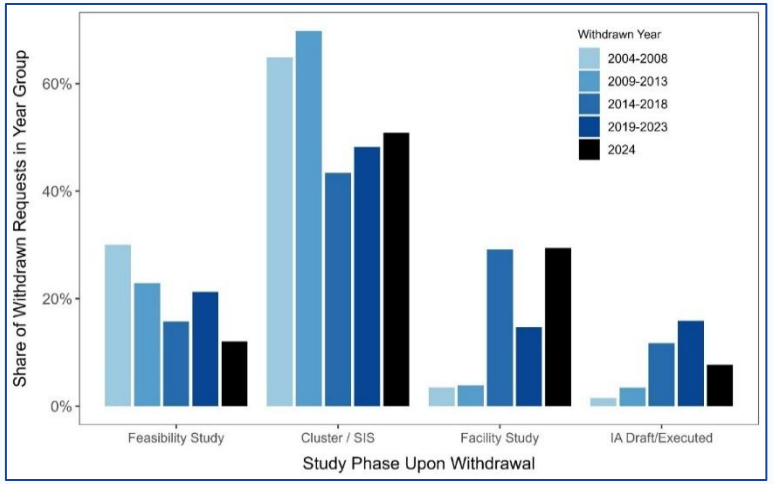
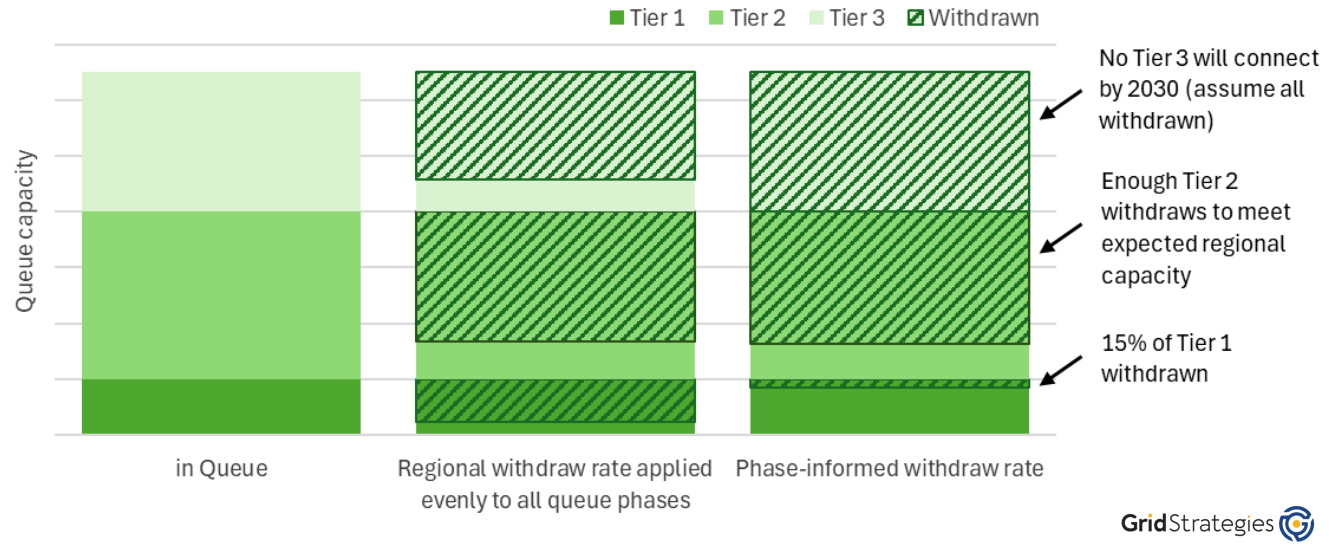


Illustration of two different methods to apply regional withdraw rates to interconnection queue data. The same amount of generation capacity withdraws in both methods.



GridStrategies

SOURCE | Rand, J., et al. (2025)

Analysis using LBNL data: Resource type

LBNL interconnection data is organized by generation resource type. When multiple resource types (e.g., gas and battery storage) are combined into one interconnection request, LBNL lists each resource type. The LBNL database includes a "type_clean" field, which summarizes all types of resources included in the interconnection entry.

These "clean" resource types are organized into a fewer number of categories in our analysis for simplicity. The cross-walk is provided in the two tables to the right.

LBNL Clean Type	Resource Type
Battery	Battery
Offshore Wind+Battery	Battery Hybrid
Other+Battery	Battery Hybrid
Solar+Battery	Battery Hybrid
Solar+Other+Battery	Battery Hybrid
Solar+Wind+Battery	Battery Hybrid
Wind+Battery	Battery Hybrid
Geothermal	Geothermal
Solar+Other	Hybrid
Solar+Wind	Hybrid
Wind+Other	Hybrid
Hydro	Hydro
Offshore Wind	Offshore Wind
Other	Other
Hydrogen	Other Storage
Other Storage	Other Storage
Solar	Solar
Battery+Other Storage	Storage Hybrid
Other+Battery+Other Storage	Storage Hybrid
Solar+Battery+Other Storage	Storage Hybrid
Solar+Wind+Other Storage	Storage Hybrid
Wind	Wind

LBNL Clean Type	Resource Type
Coal	Coal
Gas+Battery	Firm Hybrid
Gas+Battery+Diesel	Firm Hybrid
Gas+Coal	Firm Hybrid
Gas+Diesel	Firm Hybrid
Gas+Oil	Firm Hybrid
Gas+Other	Firm Hybrid
Geothermal+Battery	Firm Hybrid
Hydro+Battery	Firm Hybrid
Oil+Battery	Firm Hybrid
Oil+Coal	Firm Hybrid
Oil+Other	Firm Hybrid
Other+Coal	Firm Hybrid
Other+Diesel	Firm Hybrid
Solar+Diesel	Firm Hybrid
Solar+Gas	Firm Hybrid
Solar+Gas+Battery	Firm Hybrid
Solar+Geothermal	Firm Hybrid
Solar+Hydro	Firm Hybrid
Wind+Gas	Firm Hybrid
Gas	Gas
Diesel	Oil
Oil	Oil
Nuclear	Nuclear

GridStrategies

SOURCE | NERC "ES&D" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Accredited capacity

No resource will produce electricity at its rated capacity ("nameplate") all the time. To account for this, regions apply an accredited value to a resource to indicate a percentage of the nameplate capacity that can be expected to perform during peak demand. The accredited value of a resource varies by fuel type, season, year, and geographic location.

Each region calculates accredited capacity differently. Some consider historic forced outages of a resource type (which tend to overestimate availability) while others use modeling tools to determine how much load a resource can be expected to carry in future years given numerous system dynamics.

The LBNL interconnection queue database provides nameplate values for all generators in the queues. To ensure only a reasonable amount of new resources are accounted for in our analysis, we seasonally accredit each resource type based on the region-specific method used locally for resource accreditation. If a region does not use seasonal or resource-specific accreditation, a neighboring region's method is used.

Unless otherwise noted:

- Battery Hybrid resources are equivalent to battery resources' accredited values
- Firm Hybrid resources are the average of firm resources' accredited values
- Hybrid resources are the average of wind and solar resources' accredited values
- Other resources are the average of any remaining resources' accredited values not otherwise listed

Region	Accreditation Method & Source	Notes
MISO	2025-2026 DLOL	Summer & winter values. Battery resource uses storage (blended) and storage hybrid uses pumped storage DLOL. MISO values are also used for all other regions' resources that are not otherwise noted.
SPP	ELCC for Summer 2026	Summer values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	ELCC for Winter 24/25	Winter values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	25/26 EFORd	Summer & winter values used for all non variable resources. Oil and other resources are RICE with on-site storage, gas is CC. Values also used for ERCOT other; WECC summer other storage.
ISO-NE	CAR-SA: Impact Analysis 1/14/26	Summer & winter values. Used for solar, wind, and hydro resources
ISO-NE	2025 Capacity, Energy, Loads, and Transmission (CELT) Report	Summer & winter values. CELT used for battery, battery hybrid, coal, gas, nuclear, offshore wind, oil, other, and other (pumped) storage resources.
NYISO	2025-2026 Final Capacity Accreditation Factors	Summer values used for both seasons. Rest of state values used for battery (6-hour), hydro, offshore wind, other, other storage (pumped storage), solar, wind.
NYISO	2024 Review of EFORd	Summer & winter values. NYCA values used for coal (steam turbine), gas (CC), nuclear (steam turbine), oil (jet engine). NYISO values are also used for SERC-E summer battery and summer wind.
PJM	2027/2028 ELCC Class Ratings	Summer values used for both seasons for all resources. Battery is 6-hour CSR, battery hybrid is configuration 3, gas is CC, other is waste-to-energy, other storage is other unlimited resources, solar is fixed-tilt, storage hybrid is configuration 1. PJM values also used for SERC-E hydro, nuclear, oil, other, and other storage resources.
ERCOT	25/29 CDR	Summer & winter values for battery (6-hr), other storage (12-hr), solar, and wind. Values also used for SERC-FP and SERC-SE battery.
SERC	2025 CRP Chapter 3	Winter values used for both seasons. 2030 Reference case used for battery (standalone BESS), battery hybrid (synergistic BESS), offshore wind (avg. ELCC for first 800MW), solar (avg. ELCC for first 10 GW of standalone), wind (avg. ELCC for DEP and DEC for first 300 MW).
SERC	2023 Wind ELCC Study	Average ELCC of 5GW and 15GW standalone solar used for all SERC regions' summer solar.
Southwest	E3 2023 Resource Adequacy in the Desert Southwest	2033 values also used for WECC regions' winter battery, summer hydro, summer nuclear, winter and summer wind (unless otherwise stated).
Northwest	E3 2025 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results	Winter values for Greater Northwest used for WECC regions' gas, other storage, solar, wind (unless otherwise stated).
Northwest	E2 2019 Resource Adequacy in the Pacific Northwest	Winter values for 2030 Reference scenario used for WECC regions' coal, geothermal, hydro, nuclear (unless otherwise stated).
CAISO	2026 Net Qualifying Capacity (NQC) for RA Resources	Summer and winter values used for CAISO geothermal, hydro, other (biomass), solar, wind. Values also used for other WECC regions' other, solar, hydro and geothermal (unless otherwise stated).
National	NREL VRE ELCC Study	Median offshore wind used for SERC-FP (SERC), ERCOT, WECC-NW (NorthernGrid), CAISO

Adding historically available interregional transfer capability to the seasonal capability analysis

The EIA historical imports included in the charts on slides 16 and 29 take the difference between the historical import availability (2015 and 2025) from the U.S. EIA Form 930 data and the 2030 firm import assumptions in the LTRA. The last column subtracts imports from demand in all peak hours over the last decade and shows the minimum reduction in in-region generation due to imports.

For New York, an additional 1,250 MW of import availability was added to the EIA Form 930 data to account for the energization of the Champlain Hudson Power Express transmission line.

Comparison of on-peak net imports in four regions as assumed by LTRA against actual, in MW. Exports are negative.

	LTRA 2026 Assumption	LTRA 2030 Assumption	Historical Availability (2015-2025)
MISO	2,809	2,509	5,344
SPP	-18	-78	1,421
ISONE*	567	84	2,464
NYISO	3,405	3,486	2,730†
PJM	3,840	0	2,937‡

*Data for New England (ISONE) predates completion of the 1200 MW New England Clean Energy Connect with Hydro Quebec, so on-peak imports will likely be higher going forward.

† EIA data for New York does not include the Champlain Hudson Power Express, a 1,250 MW line connecting Quebec to New York City that is slated for completion in 2026. Once that is included, NYISO imports should be roughly in line with the LTRA.

‡ The EIA data show PJM was exporting during most peak demand periods over the last decade, so it is not possible to estimate the historical availability of imports for PJM. PJM administratively sets its capacity benefit of ties (non-firm imports) at 1.5% of nameplate generation procured in the capacity market, calculated here as 1.5% for 195,831 MW in the 2025/2026 Base Residual Auction. In its 2023 reserve margin analysis, PJM calculated 6,474 MW in total diversity benefit with its neighbors, much higher than the capacity benefit of ties shown in the table.

GridStrategies

SOURCE | EIA, "About the EIA-930 data" (accessed Feb. 2026); PJM, "2025/26 Base Residual Auction Report" (2024); Brooks, A. et al. (2025)

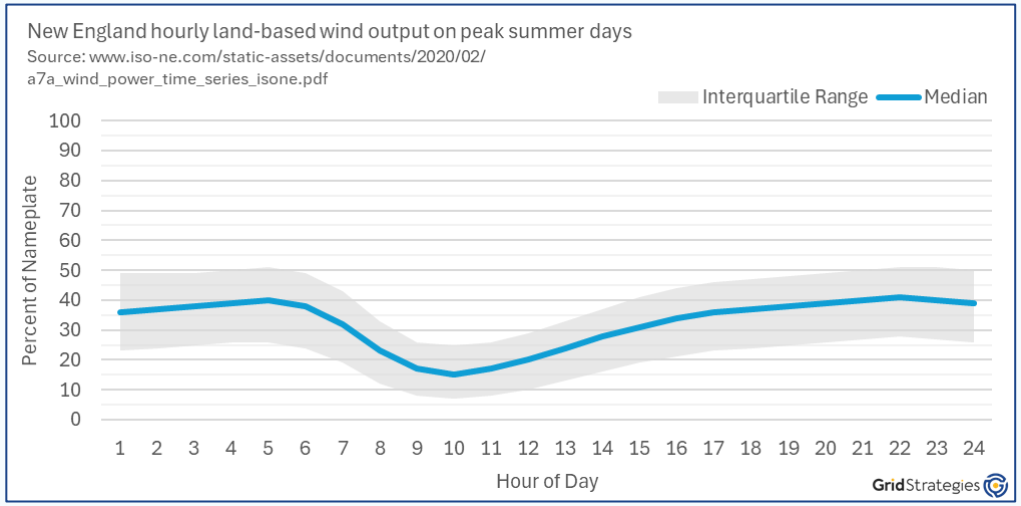
Analysis using LBNL data: New England wind and solar production

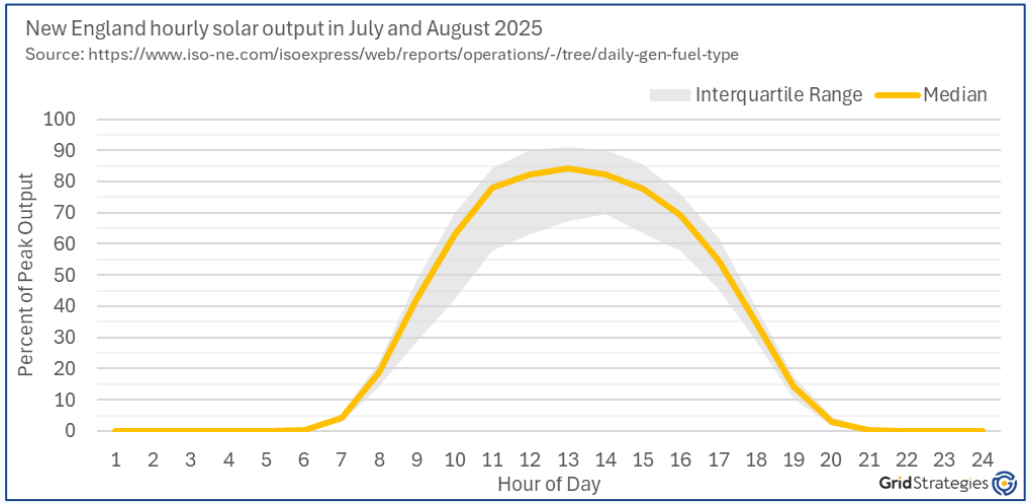
In order to use LBNL data for energy analysis for New England, we compare the amount of Tier 1 and Tier 2 LBNL data against NERC (slide 46). This required an understanding of the generation output in New England during summer months for different resource types.

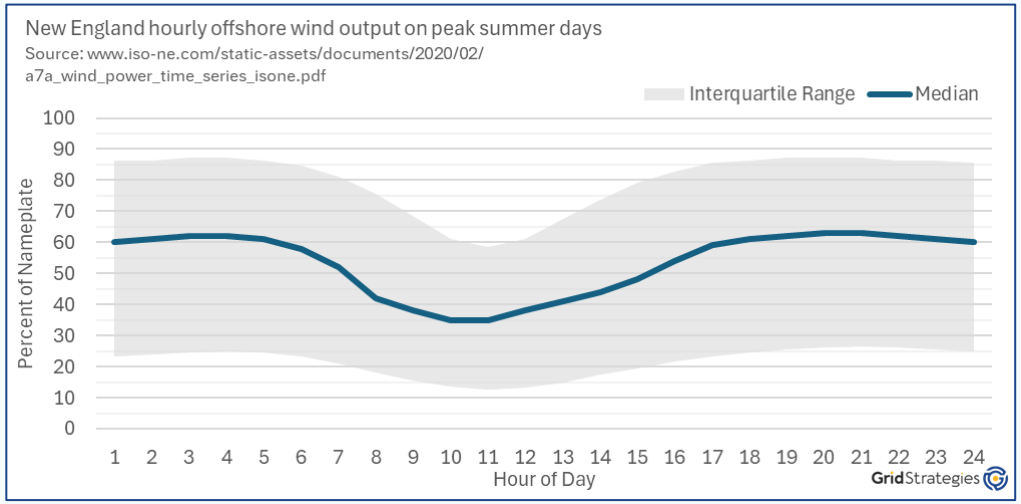
On the right are the hourly median and interquartile range for wind and offshore wind production in New England during peak demand days. This data was collected between 2012 and 2018 by ISONE to help them understand wind output during times of grid stress.

Also shown is the median and interquartile range for average hourly solar output in July and August of 2025, also from data collected by ISONE.

The hourly median data was used to estimate the output of both land-based and offshore wind in New England during peak summer 2029.







GridStrategies

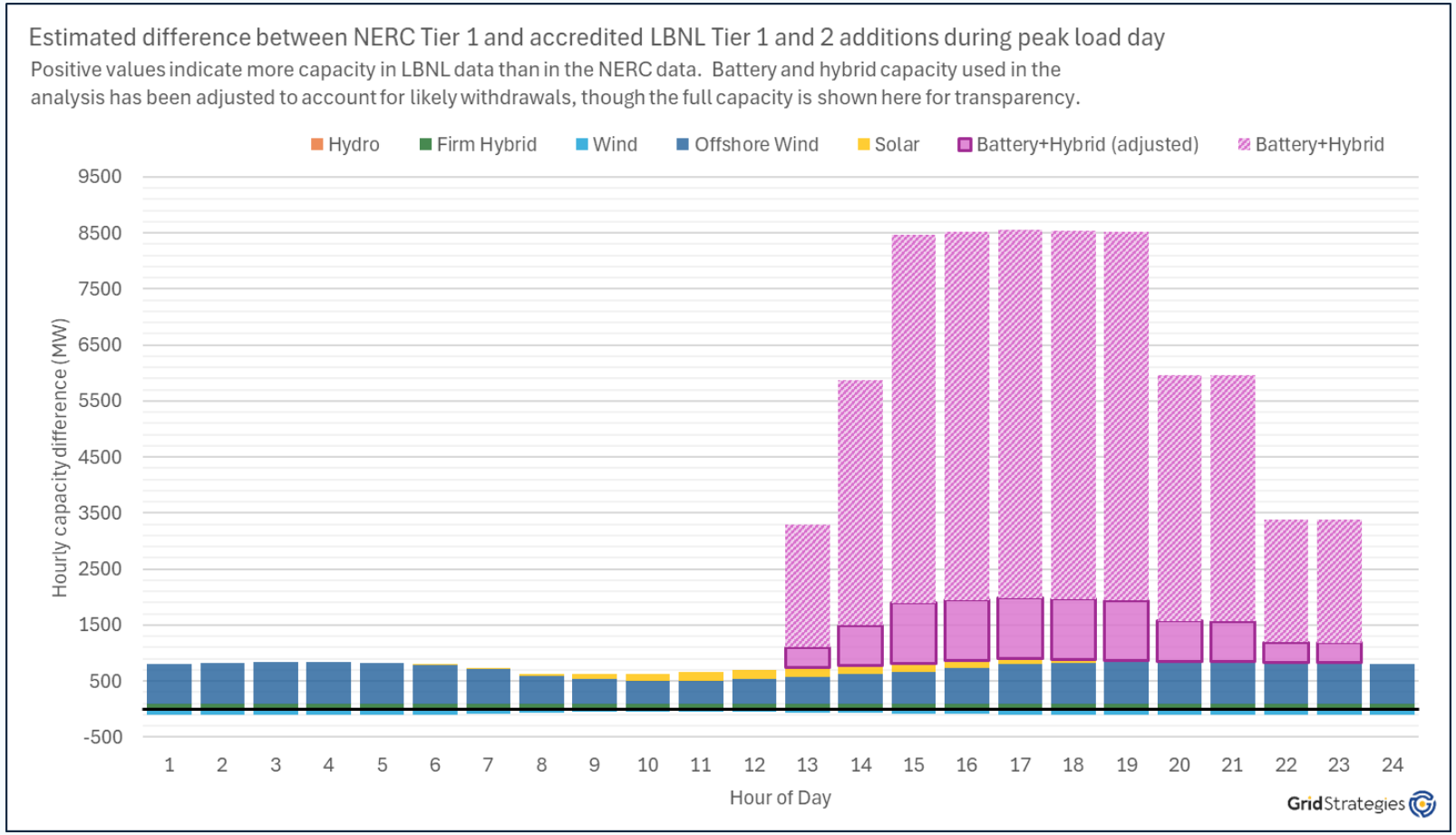
SOURCE | Judd, S. "Wind and Power Time Series Modeling of ISO-NE Wind Plants" (2020); ISONE "2025 Hourly Solar Generation" (2026)

Analysis using LBNL data: New England hourly production

Shown here is the potential change in hourly energy output for New England on peak load days given the different resource mixes between the LBNL and NERC data. Positive values indicate LBNL recorded more capacity for that resource type while negative values indicate NERC recorded more capacity.

As explained on slide 45, we adjusted the hourly production of each resource type to match expected peak day behavior, given regional resource accreditation methods. Battery and battery hybrid resources are expected to discharge at partial capacity for all hours of unserved energy, modulating their output so that no one resource discharges for longer than 6 hours. Given the large quantity of battery and hybrid resources in the LBNL data, these resources were additionally discounted by the historic withdraw rate of the region.

Given the data available, we cannot replicate the energy inadequacy analysis presented in the LTRA exactly. We provide this rough estimate to understand how different generation assumptions would impact unserved energy results.



SOURCE | NERC "2025 LTRA" (2026); NERC "2024 LTRA" (2025); NERC "ES&D" (2026); Rand, J. et al. (Aug. 2025)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-148:
Department Order No. EA-216-E

United States
Department of Energy

Office of Electricity

TransAlta Energy Marketing (U.S.) Inc.

OE Docket No. EA-216-E

Order Authorizing Electricity Exports to Canada

Order No. EA-216-E

April 27, 2021

TransAlta Energy Marketing (U.S.) Inc.
Order No. EA-216-E
Authorizing Electricity Exports to Canada

I. BACKGROUND

The United States Department of Energy (the Department or DOE) regulates electricity exports from the United States to foreign countries in accordance with section 202(e) of the Federal Power Act (FPA) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. § 205.300 et seq.). Sections 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)) transferred this regulatory authority, previously exercised by the now-defunct Federal Power Commission, to DOE.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA section 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

TransAlta Energy Marketing (U.S.) Inc. (Applicant or TEMUS) is a power marketer seeking renewal of an export authorization to export electric energy to Canada.[1] In its application, the Applicant requests export authorization for a term of five years. *See* Application of TransAlta Energy Marketing (U.S.) Inc. for Renewal of Authorization to Transmit Electric Energy to Canada (Feb. 3, 2021) (Application or App.) at 1.

TEMUS states that it is a Delaware corporation with its principal place of business in Centralia, Washington. App. at 1. TEMUS further represents that it "is an indirect subsidiary of TransAlta Corporation," which is a Canada corporation headquartered in Calgary, Alberta. *Id.* at 2. TEMUS adds that it "does not own any electric generation or transmission facilities and, as a power marketer, does not hold a franchise or service territory or native load obligation." *Id.* at 7.

[1] TransAlta Energy Marketing (U.S.) Inc.'s prior authorization to export electricity to Canada, granted in Order No. EA-216-D on April 29, 2016, expires May 17, 2021.

TEMUS represents that it "will export electricity purchased from electric utilities, federal power marketing agencies, qualifying cogeneration and small power production facilities, independent power producers, and other sellers." App. at 7. TEMUS contends that its proposed transmission would not impair the sufficiency of the electric supply within the United States, and that its proposed transmission would neither impede nor tend to impede the reliability of the domestic electric transmission system in the United States. *See id*. at 8-9.

The electric energy that TEMUS proposes to export will be wheeled over the existing authorized international electric transmission facilities listed in Exhibit C to the Application. *See* App. at 6, 10. Under this model, TEMUS will comply with terms and conditions for cross-border facilities, as well as any other export limitations DOE deems appropriate. *See id*. at 8-9. TEMUS's export transactions will be completed using the relevant procedures and/or market structures, and will be coordinated with all parties as required pursuant to the applicable market rules, as well as the reliability standards implemented by the North American Electric Reliability Corporation (NERC). *See id*.

As discussed below, TEMUS contends that its proposed exports will neither jeopardize the sufficiency of electric supply nor the reliability of the transmission grid; thus, the Applicant asserts that it meets the criteria of FPA § 202(e). *See* App. at 10.

B. Procedural History

On February 3, 2021, TEMUS filed an application with DOE requesting an export authorization for a term of five years. On March 5, 2021, DOE published notice of the application in the *Federal Register*. 86 Fed. Reg. 12,930 (Mar. 5, 2021). DOE asked for any interested parties to submit comments on the application by April 5, 2021. DOE received no comments.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, OE Order

No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, OE Order No. EA-314-A, at 2 (May 3, 2012), *renewed,* OE Order No-314-B, at 2 (Feb. 28, 2017).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, OE Order No. EA-314-B, at 2.

A. TEMUS's Requested Authorization Will Not Impair the Sufficiency of Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged FERC to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[2] and to ensure that these markets are functioning properly.[3] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations or independent system operators (RTOs/ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets

[2] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[3] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

relevant to this export authorization analysis are flawed and result in uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[4] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[5] Reliability issues are addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified NERC in 2006 to establish and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[6] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[7] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[8] Reliability oversight is designed through coordinated

[4] A related reliability analysis follows in the next section of this Order.

[5] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[6] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, Reliability*First* Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[7] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[8] *Id.* ¶ B.R1.

efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[9] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[10] DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by TEMUS's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as TEMUS, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically-integrated utility[11] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54,900 (Nov. 2, 1994). Power marketers such as TEMUS do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

---

[9] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

[10] *Id.* ¶ B.R1.

[11] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 U.S. 1, 5 (2002).

In sum, market mechanisms and reliability oversight protect against TEMUS's exports that would jeopardize domestic sufficiency of supply. Therefore, an export by TEMUS would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

B. TEMUS's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the U.S. Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach 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."[12]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions…to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay."), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any particular export will not cause an operational reliability problem. Therefore, TEMUS's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the U.S. electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[13] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted

[12] EOP-011-1 (Emergency Operations), at ¶ B.R2.

[13] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

with Presidential permit applications,[14] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (paragraph (A) of this Order). In its Application, TEMUS committed to complying with all reliability limits on border facilities. App. at 8. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. TEMUS Meets the Statutory Requirements to Export Electric Energy to Canada

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the U.S. electric power supply system. DOE has determined that the export of electric energy to Canada by TEMUS, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. TEMUS Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

TEMUS's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's regulations set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B to Subpart D, § B4.2.

DOE has determined that actions in this category do not individually or cumulatively have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.410(a). Further, in 2011, DOE formally reviewed its NEPA regulations and categorical exclusions and determined that it was appropriate to retain the B4.2 categorical exclusion. *See* National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 214, 217 (Jan. 3, 2011); National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 9981, 9982 (Feb. 23, 2011).

[14] *See, e.g.*, *AEP Tex. Cent. Co.*, OE Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, OE Order No. PP-305, at 2-4 (Nov. 17, 2008).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal," and that "[t]he proposal has not been segmented to meet the definition of a categorical exclusion." 10 C.F.R. § 1021.410(b)(2), (3). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal." *Id.* § 1021.410(b)(2). DOE finds that TEMUS's Application does not present such a circumstance, nor has it been segmented for purposes of this exclusion. TEMUS seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application. *See*, *e.g.*, *id.* §§ 1021.400(a)(1), 1021.410; 40 C.F.R. § 1501.7(e)(2).

C. Conclusion

DOE grants TEMUS's request for a five-year term. TEMUS is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Office of Electricity. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order, or continuing to export after the expiration of such an order, may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects TEMUS to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor TEMUS's compliance with these terms and conditions, including the

requirement in paragraph G of this Order that TEMUS create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject TEMUS to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide access across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that TEMUS is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by the Applicant pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[15]

Owner	Location	Voltage	Permit No.[16]
Bangor Hydro-Electric Company	Baileyville, ME	345-kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230-kV	PP-64
Bonneville Power Administration	Blaine, WA	2-500-kV	PP-10
	Nelway, WA	230-kV	PP-36
	Nelway, WA	230-kV	PP-46
CHPE LLC	Champlain, NY	±230-kV DC	PP-481
Eastern Maine Electric Cooperative	Calais, ME	69-kV	PP-32
International Transmission Company	Detroit, MI	230-kV	PP-230
	Marysville, MI	230-kV	PP-230
	St. Claire, MI	230-kV	PP-230
	St. Claire, MI	345-kV	PP-230
ITC Lake Erie Connector	Erie County, PA	320-kV	PP-412[17]
Highgate Joint Owners	Highgate, VT	120-kV	PP-82-5
Long Sault, Inc.	Massena, NY	2-115-kV	PP-24
Maine Electric Power Company	Houlton, ME	345-kV	PP-43
Maine Public Service Company	Limestone, ME	69-kV	PP-12
	Fort Fairfield, ME	69-kV	PP-12
	Madawaska, ME	138-kV	PP-29
	Aroostook, ME	2-69-kV	PP-29
Minnesota Power, Inc.	International Falls, MN	115-kV	PP-78

[15] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] These transmission facilities have been authorized but not yet constructed or placed into operation.

Minnesota Power, Inc.	Roseau County, MN	500-kV	PP-398[18]
Minnkota Power Cooperative	Roseau County, MN	230-kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230-kV	PP-305
NECEC Transmission, LLC	Beattie Township, ME	±320-kV	PP-438[19]
New York Power Authority	Massena, NY	765-kV	PP-56
	Massena, NY	2-230-kV	PP-25
	Niagara Falls, NY	2-345-kV	PP-74
	Devils Hole, NY	230-kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230-kV	PP-190
Northern States Power Company	Red River, ND	230-kV	PP-45
	Roseau County, MN	500-kV	PP-63
	Rugby, ND	230-kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450-kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320-kV DC	PP-400[21]
Vermont Electric Power Co.	Derby Line, VT	120-kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450-kV DC	PP-76

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(A) Exports by TEMUS made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that TEMUS may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(B) Exports by TEMUS made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.

[19] These transmission facilities have been authorized but not yet constructed or placed into operation.

[20] These transmission facilities have been authorized but not yet constructed or placed into operation.

[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

transmission rate of 15 MW. The gross amount of energy that TEMUS may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(C) Exports by TEMUS made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481 (issued to CHPE LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(D) Exports by TEMUS made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(E) Exports by TEMUS made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412 (issued to ITC Lake Erie Connector) to exceed an instantaneous transmission rate of 1,000 MW.

(F) Exports by TEMUS made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-5 (issued to the Highgate Joint Owners) to exceed an instantaneous transmission rate of 200 MW, nor cause a violation of the following security constrained export limits:

Vermont Total Load (MW)	Security Constrained Maximum Export (MW)
1000	0
900	40
800	90
700	125
600	150
500	170

(G) Exports by TEMUS made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-89-1 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(H) Exports by TEMUS made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-12 and PP-29 (issued to Maine Public Service Company) to exceed a coincident, instantaneous transmission rate of 97.8 MW.

(I) Exports by TEMUS made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power) to exceed an instantaneous transmission rate of 100 MW. Exports by TEMUS may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by TEMUS cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(J) Exports made by TEMUS pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power) to exceed an instantaneous transmission rate of 750 MW.

(K) Exports by TEMUS made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power/Xcel), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1050 MW on a non-firm basis.

(L) Exports by TEMUS made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that TEMUS may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(M) Exports by TEMUS made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1000 MW.

(N) Exports by TEMUS made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74, and PP-190 (issued to NYPA and Niagara Mohawk) to exceed a combined instantaneous transmission rate of 1650 MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that TEMUS may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(O) Exports by TEMUS made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the

230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(P) Exports by TEMUS made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(Q) Exports by TEMUS made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-305 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(R) Exports by TEMUS made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission, LLC) shall not exceed an instantaneous transmission rate of 1200 MW.

(S) Exports by TEMUS made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(T) Exports by TEMUS made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(J), (K), and (L) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to TEMUS.

(C) TEMUS shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) TEMUS shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. TEMUS shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) TEMUS has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of May 17, 2021 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least sixty (60) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in TEMUS's authority to export electricity.

Signed in Washington, D.C., on April 27, 2021.

Christopher Lawrence

_____

Christopher Lawrence
Management and Program Analyst
Energy Resilience Division
Office of Electricity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-149:
McCarthy Email to Department

BRACEWELL

December 12, 2025

VIA EMAIL

Grid Deployment Office
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Re: TransAlta Energy Marketing (U.S.) Inc.
Renewal Application for Authorization to Transmit Electric Energy to Canada,
GDO Docket No. EA-216-F

To Whom It May Concern:

Enclosed for filing on behalf of TransAlta Energy Marketing (U.S.) Inc. ("TEMUS") is a scanned original of TEMUS' Application for Renewal of Authorization to export electricity from the United States to Canada and related exhibits.

TEMUS has made payment in the amount of $500.00 as the filing fee for the application by credit card to the DOE, as per your instructions.

A copy of the Application is being served contemporaneously upon the Federal Energy Regulatory Commission, as required by 10 C.F.R. § 205.309.

If you have any questions regarding this filing, or if you require additional information please contact me at 202-828-5879.

Very truly yours,

Bracewell LLP

/s/ Catherine P. McCarthy
Catherine P. McCarthy
Bracewell LLP
2001 M Street, NW, Suite 900
Washington, DC 20036
Phone: (202) 828-5839
catherine.mccarthy@bracewell.com
Attorney for TransAlta Energy Marketing (U.S.) Inc.

Enclosures

cc: Federal Energy Regulatory Commission

Catherine P. McCarthy
Partner
T: +1.202.828.5839 F: +1.800.404.3970
2001 M Street NW, Suite 900, Washington, DC 20036-3310
catherine.mccarthy@bracewell.com bracewell.com

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
GRID DEPLOYMENT OFFICE

TransAlta Energy Marketing (U.S.) Inc. GDO Docket No. EA-216-F

APPLICATION OF
TRANSALTA ENERGY MARKETING (U.S.) INC.
FOR RENEWAL OF AUTHORIZATION
TO TRANSMIT ELECTRIC ENERGY TO CANADA

Daryck Riddell, Sr. Manager
Market Compliance
TransAlta Corporation
Suite 1400, 1100 1 St SE
Calgary, Alberta
T2G 1B1 Canada
Phone: (403) 267-7906
Fax: (403) 267-4764
Email: daryck_riddell@transalta.com

Catherine P. McCarthy, Partner
Bracewell LLP
2001 M Street, N.W., Suite 900
Washington, D.C. 20036-3389
Phone: (202) 828-5839
Fax: (800) 404-3970
Email: catherine.mccarthy@bracewell.com

Caroline S. Sinegar, Associate
Bracewell LLP
2001 M Street, N.W. Suite 900
Washington, D.C. 20036-3389
Phone: (202) 828-5806
Fax: (800) 404-3970
Email: caroline.sinegar@bracewell.com

Dated: December 12, 2025

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
GRID DEPLOYMENT OFFICE

TransAlta Energy Marketing (U.S.) Inc. GDO Docket No. EA-216-F

**APPLICATION OF TRANSALTA ENERGY MARKETING (U.S.) INC.
FOR RENEWAL OF AUTHORIZATION
TO TRANSMIT ELECTRIC ENERGY TO CANADA**

Pursuant to Section 202(e) of the Federal Power Act ("FPA"), 16 U.S.C. § 824(e) (2006), and Part 205, Subpart W of the U.S. Department of Energy's (the "DOE") regulations, 10 C.F.R. § 205.300, et seq., TransAlta Energy Marketing (U.S.) Inc. ("TEMUS" or "Applicant") hereby requests renewal of its authorization to transmit electric energy from the United States to Canada for a period of five years ("Renewal Application"). DOE previously renewed TEMUS' authorization to export electric energy from the U.S. to Canada as a power marketer on April 27, 2021 in Order No. EA-216-E.[1] TEMUS' authorization to transmit electricity to Canada expires on May 17, 2026. TEMUS respectfully requests that authorization be granted for an additional term of five years beginning on or before May 17, 2026 in order to avoid any lapse in authority to transmit electricity to Canada. In support of this Renewal Application, TEMUS respectfully states as follows:

[1] *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-E (April 27, 2021).

I.
DESCRIPTION OF THE APPLICANT

The exact legal name of the Applicant is TransAlta Energy Marketing (U.S.) Inc. TEMUS is a Delaware corporation with its principal place of business at 913 Big Hanaford Road, Centralia, Washington 98531-9111, and is currently authorized to do business in numerous states.[2]

On August 31, 1999, DOE issued Order No. EA 216 authorizing TEMUS to transmit electric energy from the United States to Canada as a power marketer.[3] In 2001, 2006, 2011, 2016 and 2021 in Order Nos. EA-216-A,[4] EA-216-B,[5] EA-216-C,[6] EA-216-D,[7] and EA-216-E,[8] DOE renewed TEMUS' authorization to export electric energy to Canada for five-year terms. TEMUS' current authorization to export electric energy to Canada expires on May 17, 2026.[9]

TEMUS is a power marketer with authorization from the Federal Energy Regulatory Commission ("FERC") to market electric energy and capacity at wholesale pursuant to market-based rate authorization granted by letter order issued on June 25, 1998, in FERC Docket No. ER98-3184-000.[10] TEMUS is an indirect subsidiary of

---

2 District of Columbia, Maryland, Nevada, New York, Oregon, Texas, Washington, Idaho, Utah, Colorado, Wyoming, New Mexico, Connecticut, Illinois, California, Minnesota, Michigan, Arizona, Maine, Massachusetts, New Hampshire, West Virginia, Ohio, Mississippi, Pennsylvania, Rhode Island, Louisiana, Virginia, Indiana, Wisconsin, and Missouri.

3 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216 (August 31, 1999).

4 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-A (August 16, 2001).

5 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-B (May 17, 2006).

6 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-C (May 17, 2011) ("Order No. EA-216-C").

7 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-D (April 29, 2016) ("Order No. EA-216-D").

8 *TransAlta Energy Marketing (U.S.) Inc.*, No. EA-216-E (April 27, 2021).

9 *Id.*

10 *TransAlta Energy Marketing (U.S.) Inc.*, Docket No. ER98-3184-000 (June 25, 1998) (delegated letter order).

TransAlta Corporation ("TAC"), a publicly traded Canadian corporation with headquarters in Calgary, Alberta.

In addition, TAC holds a 100% direct interest in TransAlta Energy Marketing Corp., a Canadian business corporation, which was granted market-based rate authority by FERC on April 30, 2009, in FERC Docket No. ER09-884-000.[11]

TAC also indirectly holds a 100% interest in Heartland Generation Ltd. (“Heartland”), a Canadian business corporation, which was granted market-based rate authority in the Northwest Region by FERC on October 8, 2021, in FERC Docket No. ER21-2712-000.[12] On December 20, 2021, DOE issued Order No. EA-492 authorizing Heartland to transmit electric energy from the United States to Canada as a power marketer for a five-year term.[13] Heartland’s current authorization to export electric energy to Canada expires on December 20, 2026.

In addition, through various subsidiaries, TAC is engaged in the development, financing, acquisition, ownership, and operation of independent power production facilities, and the wholesale marketing of electricity in the United States. TAC indirectly holds a 100% interest in TransAlta Centralia Generation LLC ("TCG"), a Washington limited liability company with a coal-fired electric generation facility located in Centralia, Washington. TCG is an exempt wholesale generator (“EWG”) pursuant to a letter order issued by FERC on February 25, 2000, in FERC Docket No. EG00-49-000, and TCG

[11] *TransAlta Energy Marketing Corp.*, Docket No. ER09-884-000 (Apr. 30, 2009) (delegated letter order).

[12] *Heartland Generation Ltd.*, Docket No. ER21-2712-000 (Oct. 8, 2021) (delegated letter order).

[13] *Heartland Generation Ltd.*, No. EA-492 (December 20, 2021).

holds market-based rate sales authority as granted December 16, 1999 in FERC Docket No. ER00-494-000.

TAC also indirectly holds a 100% interest in TransAlta Wyoming Wind LLC ("TWW"), a Delaware limited liability company with a wind-powered electric generating facility located in Uinta County, Wyoming. TWW is an EWG pursuant to a letter order issued by FERC on August 5, 2003, in FERC Docket No. EG03-75-000,[14] and TWW holds market-based rate sales authority originally granted on September 10, 2003 in Docket No. ER03-1025.[15]

TAC also indirectly holds a 100% interest in Lakeswind Power Partners, LLC ("Lakeswind"), a Delaware limited liability company with a wind-powered electric generating project located in Clay, Becker and Otter Tail Counties, Minnesota. Lakeswind is an EWG pursuant to a letter order issued by FERC on January 9, 2014 in FERC Docket No. EG14-12-000,[16] and was granted market-based rate authorization by FERC on November 4, 2013 in Docket No. ER13-2386-000.[17]

TAC also indirectly holds a 100% interest in Skookumchuck Dam, LLC, a Washington limited liability company with a 1 MW hydroelectric facility located in the

---

[14] *See FPL Energy Wyoming, LLC*, 104 FERC ¶ 62,088 (2003) (granting EWG status to TWW's predecessor, FPL Energy Wyoming, LLC).

[15] *See FPL Energy Wyoming, LLC*, Docket Nos. ER03-1025-000 and ER03-1025-001 (Sept. 10, 2003) (letter order granting MBR authority to TWW's predecessor, FPL Energy Wyoming, LLC). On January 8, 2014, as amended on January 31, 2014, TWW filed a revised market-based rate tariff reflecting the name change of FPL Energy Wyoming, LLC to TransAlta Wyoming Wind LLC. On March 27, 2014, FERC issued a letter order accepting the notice of succession and tariff revisions. TransAlta Wyoming Wind LLC, Docket Nos. ER14-963-000 and ER14-963-001 (Mar. 27, 2014) (letter order accepting notice of succession and tariff revisions).

[16] *See Burgess Biopower LLC, et al.*, Docket Nos. EG14-1-000, *et al.* (Jan. 9, 2014) (unpublished blanket letter order providing notice of effectiveness of EWG status for Lakeswind in Docket No. EG14-12-000).

[17] *Lakeswind Power Partners, LLC*, ER13-2386-000 (Nov. 4, 2013) (unpublished letter order granting market-based rate authority).

vicinity of Centralia, Washington. Skookumchuck Dam is self-certified as a Qualifying Facility in FERC Docket No. QF05-1-000.

TAC also indirectly holds a 100% interest in Big Level Wind LLC ("Big Level"), a Delaware limited liability company with a wind-powered electric generating facility located in Potter County, Pennsylvania. Big Level is an EWG pursuant to a letter order issued by FERC on May 8, 2019 in FERC Docket No. EG19-58-000,[18] and was granted market-based rate authorization by FERC on August 27, 2018 in Docket No. ER18-1984-000.[19]

TAC also indirectly holds a 100% interest in Antrim Wind Energy LLC ("Antrim"), a Delaware limited liability company with a wind-powered electric generating facility located in Hillsborough County, New Hampshire. Antrim is self-certified as a QF in FERC Docket No. QF19-1361-000,[20] and was granted market-based rate authorization by FERC on June 19, 2019 in Docket No. ER19-1889-000.[21]

TAC also indirectly holds a 100% interest in Ada Cogeneration LLC ("Ada"), a Delaware limited liability company with a combined-cycle, natural gas-fired cogeneration facility located in Kent County, Michigan. Ada is self-certified as a QF in FERC Docket No. QF87-529-007.[22]

TAC also holds a 49% passive interest in Skookumchuck Wind Energy Project, LLC ("Skookumchuck Wind"), through its indirect subsidiary, TA Skookumchuck Wind

---

[18] *Hillcrest Solar I, LLC, et al*., Docket Nos. EG19-54-000, et al. ((May 8, 2019) (unpublished blanket letter order providing notice of effectiveness of EWG status for Big Level Wind LLC in Docket No. EG14-12-000).

[19] *Big Level Wind LLC*, Docket No. ER18-1948-000 (Aug. 27, 2018) (unpublished letter order order granting *market*-based rate authority).

[20] *Antrim Wind Energy LLC,* Form 566, Docket No. QF19-1361-000 (filed July 12, 2019).

[21] *Antrim Wind Energy LLC*, Docket No. ER19-1889-000 (June 19, 2019) (unpublished letter order granting *market*-based rate authority).

[22] *Ada Cogeneration LLC*, Docket No. QF87-529-007 (Jan. 19, 1988) (Order granting application for certification as QF in QF87-529-000).

Holdings LLC, a Washington limited liability company with a wind-powered electric generating facility located in Lewis and Thurston Counties, Washington. Skookumchuck Wind is self-certified as an EWG in FERC Docket No. EG20-17-000,[23] and was granted market-based rate authorization by FERC on December 16, 2019 in Docket No. ER20-280-000.[24]

TAC also indirectly holds a 100% interest in White Rock Wind East, LLC ("White Rock East"), a Delaware limited liability company with a wind-powered electric generating facility located in Caddo County, Oklahoma. White Rock East is an EWG pursuant to a letter order issued by FERC on December 6, 2023 in FERC Docket No. EG23-277-000,[25] and was granted market-based rate authorization by FERC on October 30, 2023 in Docket No. ER23-2750-000.[26]

TAC also indirectly holds a 100% interest in White Rock Wind West, LLC ("White Rock West"), a Delaware limited liability company with a wind-powered electric generating facility located in Caddo County, Oklahoma. White Rock West is an EWG pursuant to a letter order issued by FERC on December 6, 2023 in FERC Docket No. EG23-277-000,[27]

[23] *Poseidon Solar,* LLC*, et al.*, Docket No. EG20-1-000, *et al*. (Jan. 15, 2020) (unpublished blanket letter order providing notice of effectiveness of EWG status for Skookumchuck Wind Energy Project, LLC in Docket No. EG20-17-000).

[24] Skookumchuck *Wind Energy Project, LLC*, Docket No. ER20-280-000 (Dec. 16, 2019) (unpublished letter order granting market-based rate authority).

[25] *River Ferry Solar LLC et al.*, Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG23-277-000 et al. (Dec. 6, 2023) (providing notice that White Rock East's EWG status became effective by operation of the Commission's regulations, 18 C.F.R. § 366.7(a)).

[26] *Horizon Hill Wind, LLC, et al.*, Docket No. ER23-2750-000 et al. (Oct. 20, 2023) (delegated letter order) (accepting White Rock East's market-based rate tariff).

[27] *River Ferry Solar LLC et al.*, Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG23-277-000 et al. (Dec. 6, 2023) (providing notice that White Rock West's EWG status became effective by operation of the Commission's regulations, 18 C.F.R. § 366.7(a)).

and was granted market-based rate authorization by FERC on October 30, 2023 in Docket No. ER23-2750-000.[28]

Further, TAC also indirectly holds a 100% interest in Horizon Hill Wind, LLC ("Horizon Hill"), a Delaware limited liability company with a wind-powered electric generating facility located in Logan County, Oklahoma. Horizon Hill is an EWG pursuant to a letter order issued by FERC on December 6, 2023 in FERC Docket No. EG23-277-000,[29] and was granted market-based rate authorization by FERC on October 30, 2023 in Docket No. ER23-2750-000.[30]

Apart from Heartland Generation Ltd., none of TEMUS' affiliates currently holds or is seeking authorization to export electricity to Canada.

Finally, Eagle Canada Common Holdings LP ("Eagle Canada Common Holdings") and BIF IV Eagle NR Carry LP ("BIF IV Eagle NR Carry" and, together with Eagle Canada Common Holdings, the "Shareholders") currently own, in aggregate, approximately 9% of the common shares of TAC. Each of the Shareholders is managed and controlled by a general partner that is an affiliate of Brookfield Corporation ("Brookfield"). Brookfield also maintains two independent directors on the TAC Board of Directors. Importantly, while Brookfield has power marketing affiliates and subsidiaries which may hold authorization to transmit electric energy from the United States to Canada as a power marketer, there is no coordination between the direct and indirect affiliates of TAC and those of Brookfield.

---

[28] *Horizon Hill Wind, LLC, et al.*, Docket No. ER23-2750-000 et al. (Oct. 20, 2023) (delegated letter order) (accepting White Rock West's market-based rate tariff).

[29] *River Ferry Solar LLC et al.*, Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG23-277-000 et al. (Dec. 6, 2023) (providing notice that Horizon Hill's EWG status became effective by operation of the Commission's regulations, 18 C.F.R. § 366.7(a)).

[30] *Horizon Hill Wind, LLC, et al.*, Docket No. ER23-2750-000 et al. (Oct. 20, 2023) (delegated letter order) (accepting Horizon Hill's market-based rate tariff).

II.
COMMUNICATIONS

Communications regarding this Renewal Application should be addressed to the following:

Daryck Riddell, Sr. Manager
Market Compliance
TransAlta Corporation
Suite 1400, 1100 1 St SE
Calgary, Alberta T2G 1B1 Canada
Phone: (403) 267-7906
Fax: (403) 267-4764
daryck_riddell@transalta.com

Catherine P. McCarthy
Partner
Bracewell LLP
2001 M Street, N.W.
Suite 900
Washington, D.C. 20036-3389
Phone: (202) 828-5839
Fax: (800) 404-3970
catherine.mccarthy@bracewell.com

Caroline S. Sinegar
Associate
Bracewell LLP
2001 M Street, N.W.
Suite 900
Washington, D.C. 20036-3389
Phone: (202) 828-5806
Fax: (800) 404-3970
caroline.sinegar@bracewell.com

III.
JURISDICTION

The authority requested of DOE by TEMUS is a necessary condition for exporting under section 202(e) of the FPA which provides that the DOE is the sole agency with jurisdiction over the proposed export of electric energy to Canada. DOE's Office of Electricity formerly held the authority to regulate the export of electric energy to a foreign

country pursuant to section 202(e) and 202(f) of the FPA.[31] This authority was delegated to DOE's Grid Deployment Office.[32]

TEMUS has obtained or will obtain any and all necessary Canadian federal and provincial authorizations to effect any proposed export that involves electricity sourced in Canada. No other known federal, state or local government has jurisdiction over the actions to be taken under the authority sought in this Renewal Application.

IV.
RENEWAL AUTHORIZATIONS AND TECHNICAL DISCUSSION

By this Renewal Application, TEMUS seeks authorization to continue to transmit electric energy, on either a firm or interruptible basis, to Canada. TEMUS desires to continue its exports of electrical energy acquired from U.S. generating sources to Canada over international electric transmission facilities. The Presidential Permits under which the relevant border facilities were constructed and maintained, and details related thereto, are set forth in Appendix C.

Pursuant to Section 202(e) of the FPA, before DOE grants authorization to export electricity, it first evaluates the impact of the export on the reliability of the U.S. electric system. DOE approves an application to export electricity unless it finds that "the proposed transmission would impair the sufficiency of electric supply within the United States," or that "the proposed transmission ... would impede or tend to impede the

[31] *See* Redelegation Order No. S4-DEL-OE1-2021-2 (rescinded).

[32] *See* Delegation Order No. S1-DEL-S3-2023; Redelegation Order No. S3-DEL-GD1-2023. A new hierarchical chart posted by DOE on November 20, 2025 shows that the Grid Deployment Office is no longer listed as part of the organization, which is now expected to be absorbed by the Office of Critical Minerals and Energy Innovation. However, it appears regulatory authority over the export of electric energy to a foreign country pursuant to section 202(e) and 202(f) of the FPA has yet to be redelegated within DOE as of the date of submittal of this Application.

coordination in the public interest of facilities subject to the jurisdiction of the Commission." 16 U.S.C. § 824(e). In applying these two criteria to requests for export authorizations submitted by electric power marketers such as TEMUS, DOE has declined to follow a rigid application of the information filing requirements set forth in DOE's regulations and instead has used a flexible approach to account for the unique nature of power marketers.[33]

TEMUS does not own any electric generation or transmission facilities and, as a power marketer, does not hold a franchise or service territory or native load obligation. Moreover, none of TEMUS' affiliates owns any electric transmission facilities other than generator interconnection facilities[34] and TEMUS is not affiliated with an entity that holds a franchise or service territory. Thus, TEMUS has no "transmission system" of its own on which power exports could have a reliability or stability impact.

Specifically, with respect to the first criterion used to analyze applications to export electricity, TEMUS is a power marketer that will export electricity purchased from electric

---

[33] *See, e.g., Morgan Stanley Capital Group Inc.*, No. EA-185-A-CN (Aug. 14, 2000); *NorAm Energy Servs., Inc.*, No. EA-105-CN (Aug. 16, 1996); *MidCon Power Servs. Corp.*, No. EA-114 (July 15, 1996); *USGen Power Servs.*, No. EA-112 (June 27, 1996); *CNG Power Servs. Corp.*, No. EA-110 (June 20, 1996); *Destec Power Servs., Inc.*, No. EA-113 (May 31, 1996).

[34] TEMUS notes, however, that an affiliate, TransAlta Generation Partnership ("TGP"), owns transmission facilities located entirely within the Province of Alberta, Canada. TGP's facilities are subject to the control of the Alberta Electric System Operator ("AESO"), an Independent System Operator that provides open access and non-discriminatory transmission service pursuant to the AESO transmission tariff, mitigating any vertical market power concerns. *See, e.g., ENMAX Energy Marketing, Inc.* 109 FERC ¶ 61,143 (2004) (accepting updated market power analysis for filing and acknowledging that the AESO provides open access and non-discriminatory transmission service); *TransAlta Enterprises Corporation*, 75 FERC ¶ 61,268 at 61,875 (1996) (concluding that the general form of open access transmission arrangements in Alberta effectively mitigate any transmission market power concerns and meet the general principles of transmission comparability in Order No. 888) and *ENMAX Energy Marketing, Inc.*, Docket No. ER01-2508-003 (Feb. 12, 2009) (letter order accepting updated market power analysis and acknowledging that the AESO provides open access and nondiscriminatory transmission service).

utilities, federal power marketing agencies, qualifying cogeneration and small power production facilities, independent power producers, and other sellers. As DOE has recognized, the "power purchased by a power marketer is, by definition, surplus to the needs of the selling entities" and "[w]ith no native load obligations, the power marketer is free to sell its power portfolio on the open market domestically or as an export."[35] Thus, an export of electricity "occurring under such circumstances" would not impair the sufficiency of electric supply within the U.S.[36]

DOE has interpreted the second criterion used to analyze applications to export electricity "primarily as an issue of the operational reliability of the domestic electric transmission system."[37] As noted above, TEMUS does not own or control any electric power supply system in the United States. Additionally, in making the necessary commercial arrangements and obtaining transmission capacity necessary to export electricity under the authorization requested herein, TEMUS will comply with existing industry procedures for obtaining transmission capacity, including reserving transmission service in accordance with FERC's Open-Access Same-Time Information System ("OASIS") and scheduling delivery of the export with the appropriate Regional Transmission Organization(s) or Independent System Operator(s) and/or Balancing Authority areas.

Additionally, the DOE has consistently found that the “power purchased by a power marketer is, by definition, surplus to the needs of the selling entities” and “[w]ith no native load obligations, the power marketer is free to sell its power portfolio on the open market

[35] Order No. EA-216-D at 2.
[36] *Id. See also Powerex Corp.*, No. EA-171-E at 6-7 (Sept. 10, 2020).
[37] Order No. EA-216-D at 2.

domestically or as an export."[38] Accordingly, DOE has routinely granted export authorization to power marketers, even those with affiliates owning electric generation facilities and serving native load obligations.[39] The DOE has not considered power marketers' affiliated generation as part of its scope of review for applications for export authorization pursuant to FPA Section 202(e), and there is no need for it to do so in order to perform its statutory obligation as directed by Congress.

TEMUS will schedule its exports from the U.S. in compliance with all applicable reliability criteria, standards and guides as are set out by the North American Electricity Reliability Corporation ("NERC") (or any successor organization), the North American Energy Standards Board (or any successor organization) and regional reliability councils and as applied by U.S. transmission providers.

V.
CONSISTENCY WITH LAWS

Authorization of the exports proposed by TEMUS is consistent with the United States–Mexico–Canada Agreement ("USMCA"), the replacement to NAFTA, and U.S. energy policy and will foster development of a more efficient and competitive North American energy market. TEMUS will conduct all operations pursuant to this Authorization in accordance with the provisions of the FPA and pertinent rules, regulations and orders adopted or issued thereunder, and in conformity with the reliability criteria, standards and guidelines of the NERC, regional reliability councils, and Balancing

[38] *See, e.g.*, Order No. EA-216-C at 2.

[39] *See, e.g.*, *Brookfield Renewable Trading and Marketing LP*, Order No. EA-465-A at 3 (Mar. 25, 2024); *Luminant Energy Co., LLC*, Order No. EA-472-A at 2 (May 30, 2024); *Boston Energy Trading and Marketing LLC*, Order No. EA-464-A at 2-3 (Feb. 21, 2024); *ENGIE Energy Marketing NA, Inc.*, Order No. EA-508 at 2 (June 24, 2024).

Authorities, including any applicable regional transmission organizations or independent system operators. Compliance with these statutes, rules, regulations, and orders will ensure that the proposed transmission will not impede or tend to impede the regional coordination of electric utility planning or operation.

TEMUS believes that DOE is not required to conduct an environmental assessment or an environmental impact statement in connection with this Renewal Application and that DOE's approval of this Renewal Application is eligible for categorical exclusion under Appendix B to Subpart D, paragraph B4.2 of the revised DOE regulations implementing the National Environmental Policy Act of 1969.

VI.
PROCEDURAL ISSUES

If required by DOE, TEMUS agrees to abide by general conditions consistent with those set forth in TEMUS' existing DOE electricity export authorizations, as applicable.[40] TEMUS respectfully submits that it satisfies the requirements of Section 202(e) of the FPA and Part 205, Subpart W of DOE's regulations applicable to applications for authorization to transmit electric energy from the United States to Canada. TEMUS respectfully requests waiver of the requirement to file this Renewal Application six months in advance of the authorization requested herein to allow issuance of an order renewing TEMUS' authorization to transmit electric energy to Canada on or before May 17, 2026, when TEMUS' current authorization expires. TEMUS also requests any additional waivers deemed necessary for DOE to issue the order requested herein.

[40] *See, e.g.*, Order No. EA-216-D at 5-13.

VII.
EXHIBITS

The following exhibits identified in the DOE's regulations are attached hereto as follows:

Exhibit A: Agreements

(Not Applicable)

Exhibit B: Legal Opinion of TEMUS' Counsel

Exhibit C: Transmission system information (submitted in lieu of maps)

Exhibit D: Irrevocable Limited Power of Attorney

(Not Applicable)

Exhibit E: Statement of any Corporate Relationship or Existing Contract which in any way Relates to Control or Fixing of Rates for the Purchase, Sale or Transmission of Electric Energy

(Not Applicable)

Exhibit F: Operating Procedures Regarding Available Capacity and Energy

(Not Applicable)

Exhibit G: Verification

To the extent necessary, TEMUS requests a waiver of the requirement to provide the exhibits that are not applicable to this Renewal Application, as noted above.

Pursuant to the requirement of 10 C.F.R. § 205.309, a copy of this Renewal Application is being provided to:

Federal Energy Regulatory Commission
Office of the Secretary
888 First Street, N.E.
Washington, DC 20426

VIII.
CONCLUSION

For the foregoing reasons, TEMUS respectfully requests that the DOE issue an order renewing TEMUS' authorization to transmit electric energy to Canada for a period of five years, effective upon issuance of the order but no later than May 17, 2026.

Respectfully submitted,
/s/ Catherine P. McCarthy

Catherine P. McCarthy, Partner
Bracewell LLP
2001 M Street, N.W., Suite 900
Washington, D.C. 20036-3389
Phone: (202) 828-5839
Fax: (800) 404-3970
catherine.mccarthy@bracewell.com

December 12, 2025

EXHIBIT A

Agreements

(Not Applicable)

EXHIBIT B

Opinion of Legal Counsel

Final

LEGAL OPINION

The following opinion is given in support of the Renewal Application of TransAlta Energy Marketing (U.S.) Inc. for Renewal of Authorization to Transmit Electric Energy to Canada, which was originally granted in Order No. EA-216 and renewed by Order Nos. EA-216-A, EA-216-B, EA-216-C, EA-216-D, and EA-216-E dated December 11th, 2025.

1) I am a barrister and solicitor at law, authorized to practice law in the Province of Alberta.

2) I am Director, Corporate Legal for TransAlta Corporation, which is the ultimate parent company of TransAlta Energy Marketing (U.S.) Inc.

3) TransAlta Energy Marketing (U.S.) Inc. is duly incorporated, validly existing and in good standing as a corporation under the laws of the State of Delaware.

4) TransAlta Energy Marketing (U.S.) Inc. has full corporate power and authority to buy, sell, or act as a marketer in the sale and exportation of electric energy as requested in the Renewal Application.

K. Galloway

Kelly Galloway
Director, Corporate Legal
TRANSALTA CORPORATION

EXHIBIT C

Transmission System Information

International Electric Transmission Facilities for TEMUS Exports to Canada

Present Owner	Location	Voltage	Presidential Permit No.[1]
Bangor Hydro-Electric Company	Baileyville, ME	345-kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230-kV	PP-64
Bonneville Power Administration	Blaine, WA Nelway, WA Nelway, WA	2-500-kV 230-kV 230-kV	PP-10 PP-36 PP-46
CHPE, LLC	Champlain, NY	±230-kV DC	PP-481[2]
Eastern Maine Electric Cooperative	Calais, ME	69-kV	PP-32
International Transmission Company	Detroit, MI Marysville, MI St. Claire, MI St. Claire, MI	230-kV 230-kV 230-kV 345-kV	PP-230 PP-230 PP-230 PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320-kV	PP-412[3]
Long Sault, Inc.	Massena, NY	2-115-kV	PP-24
Maine Electric Power Company	Houlton, ME	345-kV	PP-43
Maine Public Service Company	Limestone, ME Fort Fairfield, ME Madawaska, ME Aroostook, ME	69-kV 69-kV 138-kV 2-69-kV	PP-12 PP-12 PP-29 PP-29
Minnesota Power, Inc.	International Falls, MN Roseau County, MN	115-kV 230 kV	PP-78 PP-61
Minnkota Power Cooperative	Roseau County, MN	230-kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230-kV	PP-399
New York Power Authority	Massena, NY Massena, NY	765-kV 2-230-kV	PP-56 PP-25

[1] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[2] Currently under construction and not yet operational as of December 2025.

[3] These transmission facilities have been authorized but not yet constructed or placed into operation.

	Niagara Falls, NY Devils Hole, NY	2-345-kV 230-kV	PP-74 PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230-kV	PP-190
Northern States Power Company	Red River, ND Roseau County, MN Rugby, ND	230-kV 500-kV 230-kV	PP-45 PP-63 PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	± 450-kV DC	PP-299[4]
TDI New England	Alburgh, VT	±320-kV DC	PP-400[5]
Vermont Electric Power Co.	Derby Line, VT	120-kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	± 450-kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME Madawaska, ME Easton, ME Baileyville, ME	69 kV 138 kV 7.2 kV 345 kV	PP-497 PP-498 PP-499 PP-500

[4] These transmission facilities have been authorized but not yet constructed or placed into operation.

[5] These transmission facilities have been authorized but not yet constructed or placed into operation.

EXHIBIT D

Irrevocable Limited Power of Attorney

(Not Applicable)

EXHIBIT E

Statement of Corporate Relationships

(Not Applicable)

EXHIBIT F

Operating Procedures

(Not Applicable)

EXHIBIT G

Verification

Final

VERIFICATION OF APPLICATION

I, Joel Hunter, having knowledge of the matters set forth in the above Renewal Application of TransAlta Energy Marketing (U.S.) Inc. for Renewal of Authorization to Transmit Electric Energy to Canada, hereby verify that the contents thereof are true and correct to the best of my knowledge and belief.

To the best of my knowledge and belief, TransAlta Energy Marketing (U.S.) Inc. will take those actions required of it to do business as authorized in the States in which it will operate, and has complied with or is in the process of complying with all U.S. Federal and State laws regarding the matters contemplated in the Renewal Application.

Joel Hunter
EVP, Finance & Chief Financial Officer

SUBSCRIBED AND SWORN before me, a notary public in and for the Province of Alberta, this 11th day of December 2025.

Kelly Galloway

My Commission does not expire.

KELLY ALLISON GALLOWAY
Barrister & Solicitor

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-150:
D. Or. Amended Preliminary Injunction Order

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, *et al.*,

Plaintiffs,

and

STATE OF OREGON, *et al.*,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, *et al.*,

Defendants,

and

PUBLIC POWER COUNCIL, *et al.*,

Intervenor-Defendants.

Case No. 3:01-cv-640-SI

AMENDED PRELIMINARY INJUNCTION ORDER[1]

Michael H. Simon, District Judge.

[1] As explained in the concurrently filed Amended Opinion and Order, the Court issues the following Amended Preliminary Injunction Order in response to Plaintiffs' Motion for Clarification, ECF 2669, to address typographical errors and clarify the Court's intent. Federal Defendants either take no position on or do not object to the amendments. ECF 2670 at 2 n.2.

This matter comes before the Court on the motions for preliminary injunctive relief (hereafter, "Motions") filed by Plaintiffs and Intervenor-Plaintiff State of Oregon. The Court has reviewed the filings submitted by all Parties, taken oral argument, and, pursuant to an Opinion and Order filed concurrently herewith, GRANTED the Motions. Accordingly, the Court hereby ORDERS, until this Court orders otherwise, or until such time as the parties agree in writing to amend, supersede, or terminate this Preliminary Injunction:

A. Emergency Protocols, Pre-Coordinated Operations

A. Emergency Protocols. Nothing in this Order shall affect the content or applicability of the Emergency Protocols, Appendix 1 to the 2026 Water Management Plan (Attachment 1 to this Order), which allow modification of the operations ordered herein upon occurrence of specified emergency conditions.

B. Pre-Coordinated Operations and Variances. Nothing in this Order shall prohibit the use of pre-coordinated operations and variances described in section 4 of the 2025 Fish Operations Plan (Attachment 2 to this Order), including as needed to ensure proper functioning of adult fish ladders. Moreover, nothing in this Order shall prohibit application of the short-term adjustments in operating pool elevations pursuant to section 4 of the 2025 Fish Operations Plan for any dam subject to operating pool elevation restrictions under this Order, regardless of whether such dam is listed in that section 4.

B. Fish Passage Spill Operations Injunction

A. Definitions:

1. "125% Gas Cap spill" means spill to the maximum level that meets, but does not exceed, the Total Dissolved Gas ("TDG") criteria allowed under state laws.

2. "FOP" means the U.S. Army Corps of Engineers' ("Corps") annual Fish Operations Plan.

3. "FPP" means the Corps' annual Fish Passage Plan.

4. "FPP spill patterns" means the project-specific spill bay gate openings reflected in the FPP tables.

5. "MIP" means Minimum Irrigation Pool elevation as measured in feet above mean sea level in the reservoir forebay.

6. "MOP" means Minimum Operating Pool elevation as measured in feet above mean sea level in the reservoir forebay.

B. Except as provided in Paragraph 3 below, Federal Defendants shall implement the spill operations set forth in Table 1 below beginning in Spring 2026 and continuing until otherwise ordered by this Court.

Table 1: Injunction spill operation

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Lower Granite	Apr. 3 – June 20 125% Gas cap spill 24 hours per day	June 21 – Aug. 31 18 kcfs 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 1 RSW) 24 hours per day
Little Goose	Apr. 3 – June 20	June 21 – Aug. 31	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2

Project	Spring spill season (early April – mid-June)	Summer spill season (mid-June – end of August)	Fall/Winter spill season (early September – mid-November; early March – early April) Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.
	125% Gas cap spill 24 hours per day until adult criteria reached[2] After adult criteria reached: 125% Gas cap spill 16 hours/day and 30% for 8 consecutive daytime hours.	30% spill 24 hours per day	Low volume surface passage via spillway weir (Bay 1 ASW @ high crest) 24 hours per day

[2] Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2026, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000 hours.

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Lower Monumental	Apr. 3 – June 20 125% Gas cap spill (uniform spill pattern)[3,4] 24 hours per day	June 21 – Aug. 31 17 kcfs 24 hour per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 8 RSW) 24 hours per day
Ice Harbor	Apr. 3 – June 20 125% Gas cap spill 24 hours per day	June 21 – Aug. 31 30% 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 2 Low volume surface passage via spillway weir (Bay 2 RSW) 24 hours per day
McNary	Apr. 10 – June 15 125% Gas cap spill 24 hours per day	June 16 – Aug. 31 57% spill 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 9 Low volume surface passage via both spillway weirs (Bay 19 and Bay 20 TSWs) 24 hours per day

[3] Monitor and manage adult conversion rates in-season via Technical Management Team (TMT) process.

[4] Suspend juvenile fish transportation at Lower Monumental to avoid within day spill fluctuation.

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
John Day	Apr. 10 – June 15 125% Gas cap spill 24 hours per day Powerhouse outflows may increase up to 80kcfs for reserves without requiring a spill variance.[5]	June 16 – Aug. 31 35% spill 24 hours per day	Sep. 1 – Nov. 15; and Mar. 1 – Apr. 9 Low volume surface passage via both spillway weirs (Bay 18 and Bay 19 TSWs) 24 hours per day Approximately 1.6 kcfs Bay 2 for adult attraction when adult ladder is watered up (not during winter maintenance).
The Dalles	Apr. 10 – June 15 40% spill up to 125% Gas cap spill[6] (Gas cap fish passage spill prioritizes spillbays 1-8 and Ice Trash Sluiceway) 24 hours per day	June 16 – Aug. 31 40% (fish passage spill prioritizes spill bays 1-8 and Ice Trash Sluiceway) 24 hours per day	Sep. 1 – Apr. 9 Ice Trash Sluiceway will operate at the lowest functional level using current FPP guidelines (~3 to 5 kcfs) 24 hours per day Scheduling routine or non-routine below waterline maintenance will be coordinated in FPOM.

[5] Increased powerhouse generation allowances will allow for additional generation to be brought on-line for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, these ranges will be utilized under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere has been maximized.

[6] TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The

Project	**Spring spill season (early April – mid-June)**	**Summer spill season (mid-June – end of August)**	**Fall/Winter spill season (early September – mid-November; early March – early April)** **Shutdown period Nov. 16 – Feb. 28/29 to address freezing issues and maintenance except as noted below.**
Bonneville	Apr. 10 – June 15 125% Gas Cap spill with upper limit to 150 kcfs until stilling basin maintenance is complete (Prioritizes concurrent operation of spillway, Power House 1 Ice Trash Sluiceway, and Power House 2 Corner Collector) 24 hours per day	June 16 – Aug 31 95 kcfs plus Powerhouse 1 Ice Trash Sluiceway and Powerhouse 2 Corner Collector 24 hours per day	Sep. 1 – Apr. 9 Powerhouse 1 Ice Trash Sluiceway will operate 24 hours per day Sep. 1 – Apr. 9 Powerhouse 2 Corner Collector will operate 24 hours per day Sep. 1 – Apr. 9 Adult attraction 24 hours per day Scheduling routine or non-routine below waterline maintenance will be coordinated in FPOM.

1. "Zero Generation Operations" as described in the 2020 CRSO EIS ROD will no longer commence as early as October 15, and will instead commence once the implementation trigger described in System Operational Request ("SOR") 2005-22 has been met. This trigger will be

---

Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.

implemented in relation to both date (implementation will be limited to periods between December 1 through February 28) and abundance.

2. The annual FOP will be used by the Federal Defendants in determining spill patterns, processes, and procedures for implementation of the operations in Table 1 and the Zero Generation Operations stated above.

3. Federal Defendants may make planned or un-planned adjustments to the injunction spill operation for the reasons set forth in the annual FOP and following the procedures set forth in the annual FOP, including deference provided to the Action Agencies for energy emergencies, human safety, or infrastructure integrity emergencies.

   a. Any adjustments taken under this paragraph shall be limited to addressing the condition(s) at issue and shall not otherwise alter the injunction spill operation.

   b. Federal Defendants shall restore the injunction spill operation as soon as practicable after the condition requiring adjustment is addressed.

   c. Beginning in 2026, Water Management Plans and FOPs must require, before curtailing voluntary spill to help carry energy reserves (e.g., as outlined in the 2025 FOP)—except as specified above for the spring period at John Day dam—due diligence implementation of preemptive actions, as well as a declaration of power system emergency and/or spill variance reporting.

d. Deviations from spill orders, including rationale and resolution, shall be updated regularly on electronic platforms available to regional sovereigns.

C. Reservoir Forebay Elevation Operations Injunction

Commencing in 2026 and until otherwise ordered by the Court, the Federal Defendants shall operate all reservoir forebay elevations operations using the operation ranges from 2025.[7] By July 1st of each year, the Federal Defendants shall provide a summary to regional fish managers of which operational criteria and authorized purposes are associated with pool elevation lower limits that exceed the required ranges for each of the dams. For Bonneville, The Dalles, and McNary dams, this summary will include a description of when and why any operation limits increased from the original designations, and what actions are needed to return to designated elevations.

D. Non-Operational Conservation Measures

The Federal Defendants included in the 2020 BiOp measures for steelhead kelt reconditioning, avian and non-native piscine predation reduction, and Snake River Sockeye transportation. Thus, the Court did not grant this requested relief, even though it would provide immediate benefit to the listed species. The Court directs the government to file quarterly reports on the status of the implementation of each of these measures. Plaintiffs have leave to file on an

---

[7] The Court allows Defendants a reasonable period of time, not to exceed two weeks from the date of this Order, to implement this Order.

In the Order, the Court set forth the ranges as represented in ECF 2665 at 6. *See* ECF 2668 at 9. Plaintiffs sought clarification regarding reservoir levels, contending that the elevations for the four Lower Snake River dams were from the 2020 BiOp, rather than from the 2025 FOP. *See* ECF 2669 at 3. As stated above, the Court orders implementation of reservoir levels at the actual 2025 operating levels. To avoid the potential of conflicting orders, the Court removes the previously-listed ranges in this Amended Preliminary Injunction Order.

expedited basis a renewed motion for preliminary injunctive relief if the government is not pursuing these measures as anticipated in the 2020 BiOp.

IT IS SO ORDERED.

DATED this 2nd day of March, 2026.

Michael H. Simon
United States District Judge

Appendix 1

Technical Management Team Emergency Protocols

COLUMBIA RIVER SYSTEM

FOR ATTACHMENT TO THE
WATER MANAGEMENT PLAN
AND OTHER APPROPRIATE ACTION PLANS

Updated December 5, 2025

1. Introduction

This document establishes a protocol that will be used by the Action Agencies for notification, consultation, and documentation in the event of an emergency concerning the operation of the Columbia River System (CRS) that impacts fish protection measures contained in the respective Biological Opinions (BiOps). The BiOps call for an annual Water Management Plan (WMP), which provides the detailed description of operations, based on the current year conditions, to ensure fish protection measures are consistent with Endangered Species Act responsibilities. This Protocol is meant to be general enough to encompass most kinds of emergencies. This Protocol pertains to short duration (approximately 1-7 days) interruptions or adjustments to protection measures for listed species that occur during the operation of the CRS.

The primary emergency types these protocols apply to are:

- Generation Emergency: the potential for or actual insufficiency of electrical generation to satisfy electrical demand or load.
- Transmission Emergency: the potential or actual loss or limitation in the ability to move electricity from the site of generation to the actual consumer or end-user.
- Fish Emergency: Unexpected equipment failures or other conditions that result in an interruption of fish protections measures.
- Other Emergency: the existence or result of extenuating circumstances which fall outside the range of normal operations, is unanticipated, and may significantly impair the ability to provide for other project uses, such as flood control or navigation, significant human health and safety concerns, or result in catastrophic impact, physical damage or failure to a dam, or other part of the physical power system. Examples include earthquakes, flood control operations, fires, navigation, dam safety, and failure of fish facilities infrastructure.

Specific Action Plans will be developed for Generation *(Completed-See Attachment 1)*, Transmission and Fish Emergencies that identify pre-emptive actions and emergency actions that will be taken consistent with this Protocol. Examples of thresholds for these types of emergencies are shown in the respective Action Plans contained in Attachments 1 and 2 of this Protocol. Action Plans are coordinated in the TMT process.

The degree and/or nature of any emergency ranges from those that require immediate action to those that are amenable to coordination among affected parties prior to action. In some instances, it is possible to plan for and develop procedures to respond to an emergency, while in other instances this is not possible. In addition, while many types of emergencies can be described for purposes of this Protocol, not all emergencies can be identified prior to the actual occurrence. Discussion of emergencies with effects of exceptional magnitude or duration will include involvement of regional executives.
Emergency actions will not be taken in place of long-term investments necessary to allow full uninterrupted implementation of the planned reservoir and dam operations while maintaining other project purposes.

Interruptions to protection measures for non-listed species are inclusive in these Protocols; however, priority will be given to protection measures for listed species.

2. Goals

The primary goal of this Protocol is to have written procedures that describe how the Action Agencies will manage the CRS to avoid or minimize emergencies impacting fish protection measures in accordance with ESA biological opinions and other operative documents such as the WMP, and provide timely communication and coordination with the TMT when they occur. When emergencies occur, the Action Agencies will work with TMT to restore the protection measures and provide the planned life cycle survival rates with priority given to in-time and in-place actions to the extent practicable. (*This does not create legal rights or obligations on the part of any party.*)

3. Definitions:

Emergency – A sudden, urgent, usually unforeseen occurrence or occasion requiring immediate action. As applied to this Protocol: when necessary, interruptions or adjustments occur to fish protection measures identified in the applicable biological opinions, the Annual Water Management Plan, and other operative documents.

Emergency Actions- Actions taken by the Action Agencies in response to an emergency that affects fish protection measures.

Action Agencies - Bonneville Power Administration (BPA), Corps of Engineers (COE or Corps), and the Bureau of Reclamation (BOR or Reclamation)

TMT - Technical Management Team is one of the Regional Forum technical teams. Adaptive management of the CRS is coordinated in the Technical Management Team public meeting process.

Water Management Plan. - The Water Management Plan (WMP) describes how the Action Agencies plan to operate the Columbia River System (CRS) projects in accordance with the governing documents identified in Section 2 of the TMT Annual Water Management Plan.

4. Emergency Protocol

4.1. Advanced Planning – Pre-Emptive Actions

When the operation of the CRS is likely to require implementing emergency actions and the event can be anticipated approximately 24 hours in advance or earlier, the Action Agencies will convene a meeting of the TMT to discuss actions to undertake with the objective of averting or minimizing impacts to fish protection measures. This Protocol contains an Action Plan (see Attachment 1) that describes pre-emptive actions that will be pursued to avoid interrupting fish protection measures.

When conditions are identified that could potentially require the use of Emergency Actions within approximately 24 hours, the responsible agency, i.e. the Action Agency which would declare the emergency, shall notify the chair and co-chairs(s) of the TMT as soon as the

situation is observed. If there is time, a TMT call or meeting will be arranged by the TMT chair or co-chair(s). If time allows, a discussion will be arranged, however, in some situations, the call may provide notification to TMT members of pre-emptive actions the responsible agency has deemed necessary.

The Action Agencies will implement all available pre-emptive actions prior to implementing emergency actions, and when feasible, the Action Agencies will implement alternate operations recommended by TMT.

4.2. Emergency Response

Emergency actions may be required as an immediate response if the pre-emptive actions fail to resolve the situation or the situation deteriorates without warning. If emergency actions are implemented as an immediate response an emergency will be declared. The Agency declaring the emergency will consider the prioritized emergency action lists provided in appendices of this Protocol, direction from TMT or other groups, standard operating procedures for specific projects, and/or guidance from appropriate responsible agencies to resolve the condition.

The Action Plans provided in the appendices of this Protocol have been discussed in the TMT forum will be used as guidance when events unfold too quickly for pre-coordination to occur. For emergencies requiring immediate action by those operating the respective hydropower project(s) or other elements necessary to sustain the function of the hydrosystem, after stabilizing the situation they will contact the chairs of the TMT and IT. The TMT chair or co-chair(s) will disseminate a notification via phone calls and emails to a "first contact list," which will include designated members from TMT and others that have requested inclusion on the first contact list as soon as practicable, but not later than the next working day. A meeting of the TMT will be convened at the earliest time available after notification of the first contacts.

5. Documentation and Follow Up Requirement

In all cases when emergency actions have been implemented, as soon as practicable, but not later than the next working day, the following information shall be provided by the agency declaring the emergency:

- Description of the emergency, how it occurred, and how long it is anticipated to last
- Description of how the emergency jeopardized system stability, public safety, or otherwise necessitated action that impacted fish protection measures.
- Identification of agencies that declared the emergency and agencies that responded to the emergency
- Identification of who was notified of the emergency
- Description of what actions were taken by each agency
- Identification of alternatives considered to reduce and offset impacts of the emergency.
- Further detailed information will be provided upon request of the TMT.

When requested by a TMT member, the TMT Chairperson will arrange for a follow-up TMT meeting or conference call to:

- Review status of the event,
- Ensure that all requirements for the implementation of emergency actions by the Action Agencies have been met and that all alternatives for offsetting adverse fish survival impacts of the implemented emergency actions have been considered, and
- Review the use of emergency action lists and revise the lists based on any lessons learned.

In general, system operations will revert to normal conditions, or as agreed upon in the TMT, when the event has been resolved or emergency actions are no longer required. The agency that declared the emergency will submit a detailed report of the incident and response at the next TMT meeting following the event unless other arrangements are arranged through the TMT process.

The Action Agencies will provide an opportunity for representatives of the region's affected parties to review the course of events and the implemented emergency actions to suggest refinements to the actions. These issues will be discussed at the next TMT meeting following the event.

6. Offsetting Adverse Effects of Emergency Response Actions

When emergency actions are implemented that cause adverse effects to fish protection measures, the TMT will assess the magnitude of the adverse effect and provide information on measures available to offset these effects. Alternative operations to offset adverse effects in-place and in-kind in a timely manner shall receive the highest priority. The members of the Regional Forum agree to cooperate in the development of this information for consideration through the TMT process.

When emergency actions impact a fish protection measure(s) included in a Biological Opinion, the appropriate agency (National Marine Fisheries Service (NMFS) or Fish and Wildlife Service (USFWS)) will consider the available information to assess whether the alternative operation used in response to the emergency situation is inconsistent with the relevant Biological Opinion(s), in that, in its expert opinion, the effects were in excess of what was contemplated in the analyses used in the respective biological opinion. If the alternative operation is determined to provide a reduction in the life cycle survival rate than that recommended in the Biological Opinion(s) analyses, then NMFS or USFWS will recommend to the federal operating agencies offsetting measures to ensure that the action satisfies Endangered Species Act requirements.

An Action Agency deciding not to provide offsets or proposing offsetting actions that are different from those recommended through the TMT process, will provide a written explanation for the record stating the decision and the basis for the decision.

Emergency Protocols Attachment

Attachment 1 – Power System Emergency Action Plan

Attachment 1

Power System Emergency Action Plan

December 5, 2025

If hydropower generation must be adjusted to support power system reliability, and this adjustment will alter planned fish operations specified in applicable biological opinions (and other guiding operative documents), Bonneville will attempt to implement the actions in the preemptive actions list below, where practicable. If these preemptive actions are unavailable, insufficient, or cannot be implemented in time, then Bonneville may implement additional actions as necessary to address the power system reliability need. The list of contingency actions below are examples of actions that can be taken to address the reliability conditions described in Section 4.4.2 of the FOP.

Where contingency action is necessary, notification to the region will be made as soon as practical, and will follow the protocols for notification, reporting, and documentation as specified in the *Technical Management Team Emergency Protocols, Appendix 1 – Emergency Protocols of the TMT Water Management Plan.*

Pre-emptive Actions (not in priority order)

- Purchase Energy and/or reserves at prices up to the applicable FERC WECC price cap.
- Request that Corps and Reclamation return all possible units to service by canceling or postponing scheduled generator or equipment outages (e.g., makes all units available).
- Request the transmission dispatcher consider adjusting transmission system maintenance or other possible actions that would allow increases or decreases in CRS generation as appropriate.
- Put into service (online) all possible generators (e.g., Grand Coulee pump-generators) while preserving sufficient energy storage to maintain reserve capability in subsequent hours
- Reshape flows within objectives at specific projects to meet immediate generation needs e.g., spill upstream projects to position water downstream.
- Cut any interruptible power commitments.
- Request adjustment of pumping schedule at Banks Lake.
- Request variance from non-power operational objectives or limits at CRS hydro projects (e.g., forebay draft limits, tailwater rate of change, recreation, irrigation, Treaty fishing, etc.)
- Reduce the amount of balancing reserves provided by the CRS to the minimum amount necessary for power system stability and reliability.
- Acquire any resources made available through the issuance of a "EEA Watch".
- After exhausting all available reserve sharing opportunities ask the transmission dispatcher to request the Reliability Coordinator to declare an Energy Emergency ALERT 1 when there is concern about sustaining required operating reserves.

Contingency Actions List

(Updated February 25, 2022)

When routine reliability tools and preemptive actions are insufficient or unavailable to resolve the power system condition, the following is a list of contingency actions that may be taken to provide reserves, voltage, energy or inertia. The order and extent of the actual implementation of the actions in this list will be dictated by each specific condition but if possible, the order at each individual dam will be followed. The actions on the list may be updated as necessary through coordination with TMT.

Contingency Actions are prioritized by tier and within each tier.

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 1	Tier 1	Tier 1	Tier 1
LWG Move Spillway Weir Hours within morning hours or next day morning	JDA shutoff adult attraction spill	**BON**: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1
LGS Move Spillway Weir Hours within morning hours or next day morning	BON shutoff adult attraction spill	**TDA**: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load
LMN Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts as coordinated with operators	**JDA**: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load
IHR Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates as coordinated with operators	**MCN**: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit
MCN Move Spillway Weir Hours within morning hours or next day morning	DWR: increase project drafts as coordinated with operators	**IHR**: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load
		LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load
		LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load
		LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load
		Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)

Appendix I, Water Management Plan

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
JDA shutoff adult attraction spill	IHR 30% of flow	LWG reduce spill to 20 kcfs	LWG reduce spill to 20 kcfs
BON shutoff adult attraction spill	LMN 30 kcfs flat	LGS reduce spill to 30% of flow	LGS reduce spill to 30% of flow
HGH & LIB modify ramping rates	LGS 30% of flow	IHR reduce spill to 30% of flow	IHR reduce spill to 30% of flow
HGH, LIB, ALF, GCL : increase project drafts	LWG 20 kcfs	MCN reduce spill to 40% of flow	MCN reduce spill to 40% of flow
DWR: increase project drafts		JDA reduce spill to 30% of flow	JDA reduce spill to 30% of flow
		TDA reduce spill to 30% of flow	TDA reduce spill to 30% of flow
		BON reduce spill to 100 kcfs	MCN generate outside 1% up to full load
		MCN generate outside 1% up to full load	BON2 operate outside 1% up to full load
		BON PH2 operate outside 1% up to full load	Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG
		Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG	
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
BON1 shut off sluiceway	BON shut off sluiceway	LWG reduce spill to 18 kcfs	LWG 18 kcfs of spill
TDA shut off sluiceway	TDA shut off sluiceway	LMN reduce spill to 30% of flow	LMN 30% of flow
BON shut off B2CC	BON shut off B2CC	MCN reduce spill to 30% of flow	MCN 30% of flow
		BON 95 kcfs	BON 50 kcfs
		BON: Generate above 1% up to full load PH2	BON: Generate above 1% up to full load PH2

Appendix I, Water Management Plan

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 4	**Tier 4**	**Tier 4**	**Tier 4**
	LWG Reduce Spill to Spillway weir only	BON 75 kcfs	BON 75 kcfs
	LGS Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only
	LMN Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only
	IHR Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only
		IHR Reduce Spill to Spillway weir only	IHR Reduce Spill to Spillway weir only
		MCN Reduce Spill to Spillway weir only	MCN Reduce Spill to Spillway weir only
Tier 5	**Tier 5**	**Tier 5**	**Tier 5**
	Reduce spill to zero at LWG	BON reduce spill to 50 kcfs	BON reduce spill to 50 kcfs
		BON reduces spill to zero	BON reduces spill to zero
	Reduce spill to zero at LGS	BON shutdown B1 Sluiceway	BON shutdown B1 Sluiceway
	Reduce spill to zero at LMN	BON shutdown B2CC	BON shutdown B2CC
	Reduce spill to zero at IHR		
Tier 6	**Tier 6**	**Tier 6**	**Tier 6**
		LWG reduce spill to zero	LWG reduce spill to zero
		LGS reduce spill to zero	LGS reduce spill to zero
		LMN reduce spill to zero	LMN reduce spill to zero
		IHR reduce spill to zero	IHR reduce spill to zero
		MCN reduce spill to zero	MCN reduce spill to zero
		JDA reduce spill to zero	JDA reduce spill to zero
		TDA reduce spill to zero	TDA reduce spill to zero

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 1	Tier 1	Tier 1	Tier 1
BON: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1	LWG Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts
TDA: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load	LGS Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates
JDA: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load	LMN Move Spillway Weir Hours within morning hours or next day morning	BON shut off sluiceway
MCN: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit	IHR Move Spillway Weir Hours within morning hours or next day morning	TDA shut off sluiceway
IHR: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load	MCN Move Spillway Weir Hours within morning hours or next day morning	Dworshak increase project drafts
LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load		
LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load		
LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load		
Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	**BON**: Generate above 1% up to full load PH2		

Appendix I, Water Management Plan

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
LWG Reduce Spill to Spillway weir only	LWG reduce spill to zero	JDA shutoff adult attraction spill	
LGS Reduce Spill to Spillway weir only	LGS reduce spill to zero	BON shutoff adult attraction spill	
IHR Reduce Spill to Spillway weir only	LMN reduce spill to zero	HGH, LIB, ALF, GCL : increase project drafts	
MCN 40% of flow	IHR reduce spill to zero	HGH & LIB modify ramping rates	
JDA 30% of flow	MCN reduce spill to zero		
TDA 30% of flow	JDA reduce spill to zero		
BON 75 kcfs	BON reduce spill to zero		
MCN generate outside 1% up to full load	TDA reduce spill to zero		
BON PH2 operate outside 1% up to full load			
Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG			
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
MCN 30% of flow	BON1 shut off sluiceway	LWG reduce spill to zero	
JDA Spillway Weir only	TDA shut off sluiceway	LGS reduce spill to zero	
BON 50 kcfs	BON shut off B2CC	LMN reduce spill to zero	
IHR reduce spill to zero		IHR reduce spill to zero	
LMN reduce spill to zero		MCN reduce spill to zero	
LGS reduce spill to zero		BON1 Shut off sluiceway	
LWG reduce spill to zero		TDA Shut off sluiceway	

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 4	**Tier 4**	**Tier 4**	**Tier 4**
BON reduce spill to zero		DWR: increase project drafts	
TDA reduce spill to zero			
Tier 5	**Tier 5**	**Tier 5**	**Tier 5**
Tier 6	**Tier 6**	**Tier 6**	**Tier 6**

Definitions

Balancing Authority - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area - The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load resource balance within this area.

BPA Power system – This term includes the Federal Columbia River hydropower projects and transmission system.

Energy Emergency Alerts – Procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. An Energy Emergency Alert may be initiated by Reliability Coordinator at the Reliability Coordinator's own request or upon the request of a Balancing Authority or a Load Serving Entity. See: https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf

Energy Emergency Watch - The EEA Watch is a communication tool that provides load serving entities a means to exchange information regarding issues that could impact the reliable operation of the power system when analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. This notice can be issued the day before the projected shortfall or if a sudden event occurs. Consumers are encouraged to conserve energy.

Energy Emergency Alert 1 - All available resources in use.

- Balance Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

Energy Emergency Alert 2 – Load management procedures in effect.

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customer' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments.

Energy Emergency Alert 3 – Firm load interruption imminent or in progress.

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Emergency Alert 0 - Termination

- When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the Energy Emergency be terminated.

Redispatch – The intentional incrementing of location-specific generation and the corresponding decrementing of different location-specific generation to mitigate loading on constrained transmission facilities.

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, NORTHWESTERN DIVISION
PO BOX 2870
PORTLAND OR 97208-2870

2025 Fish Operations Plan

1. INTRODUCTION

The 2025 Fish Operations Plan (2025 FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish[1] passage at its four lower Snake River and four lower Columbia River dams and includes spring surface spill operations (March through early April), spring and summer spill operations (early April through August), and fall/winter surface spill operations (September through mid-November). The 2025 FOP is consistent with spill operations for fish passage and the regional forum process for adaptive management and in-season management provisions outlined in the Record of Decision for the Columbia River System Operations Environmental Impact Statement (CRSO EIS ROD) dated September 28, 2020, CRSO Final EIS, 2020 National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS) Columbia River System (CRS) Biological Opinions (2020 CRS BiOps)[2], the Extensions of the 2008 Columbia Basin Fish Accords (Accord Extensions), the Corps' requirements under the Endangered Species Act (ESA), and the ongoing consultation and communications with the relevant wildlife agencies to ensure consistency with the Act. The 2025 FOP also incorporates operations outlined in Appendix B of the "U.S. Government Commitments in Support of the Columbia Basin Restoration Initiative" (USG Commitments). The USG Commitments were agreed to as part of the 2023 Memorandum of Understanding (*see* Section 3 of the MOU). Other project operations and water management actions not specifically addressed in this document will be consistent with other guiding operative documents, including the 2025 Water Management Plan (WMP), seasonal WMP updates, and the 2025 Fish Passage Plan (FPP).

In addition to discussing project-specific fish passage spill operations, the 2025 FOP identifies factors that the Corps, the Bureau of Reclamation (Reclamation), and the Bonneville Power Administration (Bonneville) (collectively referred to as the "Action Agencies") must address in the context of operating this complex system of fourteen multiple purpose projects. The 2025 FOP includes a discussion of how the Corps manages fish passage spill and total dissolved gas (TDG), identifies Planned and Routine Operational Adjustments (Section 4) that influence fish passage spill, addresses adaptive management and in-season management processes for fish passage spill and other fish operations including the juvenile fish transportation program, and describes the Corps' monthly implementation reports.

---

[1] ESA-listed salmon and steelhead.

[2] The Corps, in coordination with the other Action Agencies, and NMFS, employs the Regional Implementation Oversight Group (RIOG) and technical teams including the Technical Management Team (TMT) and Fish Passage Operations & Maintenance (FPOM) coordination group, to coordinate with state, tribal and other federal experts for recommendations for implementing operations consistent with the 2020 BiOps.

2. MANAGEMENT OF SPILL FOR FISH PASSAGE AND TDG

2.1. State Water Quality Standards for TDG

The Corps will manage spill for fish passage in 2025 consistent with the State of Washington and the State of Oregon total dissolved gas (TDG) water quality standards (WQS).[3,4] The State of Washington, Department of Ecology (WADOE) adopted a WQS rule change which became effective in 2020 allowing spring juvenile fish passage spill operations to generate specified TDG levels in project tailraces (up to 125% TDG 12 hours, 126% TDG 2 hours), so long as the specified conditions are met, including that spring juvenile fish passage spill operations do not exceed the spill levels and durations reviewed in applicable ESA consultation documents. The Environmental Protection Agency (EPA) subsequently approved the rule change and found that the ESA consultation documents ensure that any spring spill regime using the revised criteria must be performed in accordance with the spill levels and durations evaluated in ESA consultation documents for effects to ESA-listed species of all life stages, including juvenile out-migrating salmonids, resident salmonids, and adult migrating salmonids. EPA's approval of the rule further states that "compliance with the ESA consultation documents is a condition precedent for the revised criteria and so the criteria are not applicable for the purposes of the [Clean Water Act (CWA)] (i.e., have no effect for CWA purposes) without the ESA consultation documents addressing spill operations that result in TDG saturation levels above the pre-existing criterion." *Letter to WADOE from EPA Re: The EPA's Action on Revisions to the [WADOE's] Surface Water Quality Standards for the Site-Specific Total Dissolved Gas Criteria in the Columbia and Snake Rivers, and Other Water Quality Standards Revisions* dated March 5, 2020, page 9.

The State of Oregon, through its Environmental Quality Commission, approved a modification to its TDG WQS of up to 125% TDG from April 1-June15 and up to 120% TDG from June 16-August 31, so long as spring spill is "applied in a manner consistent with the applicable requirements of the federal [ESA]." (*Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem* dated December 31, 2024, page 4). Regarding Oregon's 105% TDG criterion, Oregon Department of Environmental Quality (ODEQ) clarified that this criterion does not apply to the Columbia River per their letter dated January 29, 2024. Both states have thus accommodated levels of TDG above 110% for fish passage spill operations for ESA-listed juvenile salmonids at Corps projects on the lower Snake and lower Columbia rivers, as follows:

---

[3] WASH. ADMIN. CODE § 173-201A-200(l)(f)) provides the maximum TDG criteria for each of the aquatic life use categories and displays Table 200 (I)(f) that states: "Total dissolved gas shall not exceed 110 percent of saturation at any point of sample collection." The code also addresses exceptions and adjustments, including a provision allowing for an adjustment of the TDG criteria to aid fish passage over hydroelectric dams. *See* https://apps.leg.wa.gov/WAC/default.aspx?cite=173-201A-200.

[4] OR. ADMIN. R. 340-041-0031 provides in part: "the concentration of TDG relative to atmospheric pressure at the point of sample collection may not exceed 110 percent of saturation." OR. ADMIN. R. 340-041-104(3) identifies findings the Environmental Quality Commission must make for the purpose of allowing increased spill for salmon migration. *See* https://www.oregon.gov/deq/wq/Documents/columbiaUSACEtmdlorder.pdf

Washington Administrative Code[5]:

WAC 173-201A-200(1)(f)(ii) and WAC 173-201A-200(1)(f)(ii)(A)

(ii) The TDG criteria may be adjusted to aid fish passage over hydroelectric dams that spill for anadromous juvenile fish as of the 2020 spill season. The elevated TDG levels are intended to allow increased fish passage without causing more harm to fish populations than caused by turbine fish passage. The following special fish passage exemptions for the Snake and Columbia Rivers apply when spilling water at dams is necessary to aid fish passage:

(A) TDG must not exceed:

• An average of 115 percent as measured in the forebays of the next downstream dams and must not exceed an average of 120 percent as measured in the tailraces of each dam (these averages are calculated as an average of the 12 highest hourly readings in a calendar day, relative to atmospheric pressure); and
• A maximum TDG saturation level of 125 percent calculated as an average of the two highest hourly TDG measures in a calendar day during spillage for fish passage.

WAC 173-201A-200(1)(f)(ii)(B)

(B) To further aid fish passage during the spring spill season (generally from April through June), spill may be increased up to the following levels as measured at the tailrace fixed site monitoring location:

• A maximum TDG saturation level of 125 percent calculated as an average of the 12 highest hourly TDG measures in a calendar day: and
• A maximum TDG saturation level of 126 percent calculated as an average of any two-consecutive hourly TDG measures. These TDG criteria may be applied in place of (f)(ii)(A) of this subsection during spring spill operations when applied in accordance with the following conditions:

(I) In addition to complying with the requirements of this chapter, the tailrace maximum TDG criteria at hydropower dams shall be applied in accordance with Endangered Species Act consultation documents associated with spill operations on the Snake and Columbia rivers, including operations for fish passage. The Endangered Species Act consultation documents are those by which dams may legally operate during the time that the adjusted criteria in (f)(ii)(B) of this subsection are in use.

(II) Application of the tailrace maximum TDG criteria must be accompanied by a department approved biological monitoring plan designed to measure impacts of fish exposed to increased TDG conditions throughout the spring spill season. Beginning in

[5] The text of the code is copied verbatim below for reference.

the year 2021, plans must include monitoring for non-salmonid fish species and must continue for a minimum of five years, and thereafter as determined by the department.

(III) TDG must be reduced to allowances specified in (f)(ii)(A) of this subsection if the calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of 50 fish required weekly) or non-salmonids (with a minimum sample size of 50 fish required weekly) exceeds:

- Gas bubble trauma in non-paired fins of 15 percent; or
- Gas bubble trauma in non-paired fins of five percent and gas bubbles occlude more than 25 percent of the surface area of the fin.

In accordance with WADOE's Rule Implementation Plan, if gas bubble trauma exceeds these biological thresholds, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be adjusted to allowances specified in this subsection. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above the ability to meet (f)(ii)(B) of this subsection. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of (f)(ii)(B) of this subsection.

Oregon Water Quality Standard Modification:

The Environmental Quality Commission approved the following modification[6] to the statewide standard for total dissolved gas (OAR 340-41-0031(2)) of 110 percent for the lower Columbia River at McNary, John Day, The Dalles and Bonneville dams, as provided for in OAR 340-41-0104(3):

1. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 125 percent for the period from April 1 through June 15.

2. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 120 percent for the period from June 16 through Aug. 31.

3. These limits do not apply when the stream flow exceeds the seven-day, ten-year frequency flood.

4. The modified total dissolved gas standards will apply for five years, beginning Jan. 1, 2025, through Dec. 31, 2029 (calendar years 2025, 2026, 2027, 2028, and 2029).

5. The DEQ Director may approve additional periods of application of this modification up to 120 percent total dissolved gas as calculated in 8.a)i., beyond the April 1 to Aug. 31 period, subject to subsections 8.a) to 8.c) for reasons including passing Spring Creek

[6] The text of the modification is copied verbatim below for reference.

Hatchery fish releases and other voluntary fish passage operations, maintenance activities, and biological or physical studies of spillway structures and prototype fish passage devices. The Corps must notify DEQ in writing at least one week prior to the spill describing the proposed action, including its purpose, and the location and dates of elevated total dissolved gas levels. Spill must be reduced to meet the 110 percent total dissolved gas criterion if requested by the DEQ Director.

6. Application of the tailrace maximum TDG criteria must be accompanied by a DEQ-approved biological monitoring plan designed to measure impacts to fish exposed to increased TDG conditions. Plans must include monitoring for non-salmonid fish species. Gas bubble trauma monitoring may be halted if there is a high mortality risk due to compounded effects of the evaluation procedure and adverse environmental factors such as high stream temperatures.

7. Voluntary fish passage spill during the spring spill season, occurring from April 1 through June 15, is subject to the following conditions:

   a. Spill at a dam must be reduced when:

      i. Instantaneous total dissolved gas levels exceed 127 percent of saturation, calculated as the average of any two consecutive hourly TDG measurements in the tailrace of the dam; or

      ii. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 125 percent.

   b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels to 120 percent as calculated in 8.a)i. when:

      i. The calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of fifty fish required weekly) or non-salmonids (with a minimum sample size of fifty fish required weekly) exceeds gas bubble trauma in eyes or non-paired fins of fifteen percent, or gas bubble trauma in eyes or non-paired fins of five percent and gas bubbles occlude more than twenty-five percent of the surface area of the fin or eyes. If gas bubble trauma exceeds these biological thresholds and spill is reduced, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be increased to the level specified in this order. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above 125 percent. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of 125 percent TDG levels in the tailrace of the dam.

   c. The tailrace maximum TDG criteria for spring spill in this modification will be applied in a manner consistent with the applicable requirements of the federal Endangered Species Act.

d. Physical monitoring must occur and be adequate for implementing the requirements of this order.

8. Voluntary fish passage spill during the summer spill season, occurring from June 16 through Aug. 31, is subject to the following conditions:

   a. Spill at a dam must be reduced when:

      i. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 120 percent of saturation; or

      ii. Instantaneous total dissolved gas levels exceed 125 percent of saturation in the tailrace of the dam, calculated as the average of the two highest hourly total dissolved gas measures in a calendar day.

   b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels if voluntary spill results in biological threshold exceedances when:

      i. More than 15 percent of salmonids examined show signs of gas bubble disease in their eyes or non-paired fins, or

      ii. More than five percent of salmonids examined show signs of gas bubble trauma in their eyes non-paired fins where more than 25 percent of the surface area is occluded by gas bubbles.

   c. Physical monitoring must occur and be adequate for implementing the requirements set out in this order.

9. The Corps must provide written notice to DEQ within 24 hours of any violations of the conditions in the modification as it relates to voluntary spill. Such notice must include actions proposed to reduce total dissolved gas levels or the reason(s) for no action.

10. No later than Jan. 31 following each year of this modification, the Corps must provide an annual written report to DEQ detailing the following:
    a. Flow and runoff descriptions for the spill season;
    b. Spill quantities and durations;
    c. Quantities of water spilled for fish versus spill for other reasons for each project;
    d. Data results from the physical and biological monitoring programs, including incidences of gas bubble trauma regardless of sample size;
    e. Evaluation of the relationship between observations of non-salmonid gas bubble trauma monitoring and exposure to elevated total dissolved gas levels;
    f. Description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels; and
    g. Implementation of gas abatement measures identified through adaptive management.

11. If requested, the Corps must report to the commission on any of the above matters or other matters relevant to this order.

12. The commission reserves the right to terminate or modify this order at any time.

For the purposes of Oregon's Order, ODEQ defines non-salmonid as including non-native species per their letter dated June 10, 2022 and email dated January 18, 2023. Gas bubble trauma monitoring in bi-state waters will include evaluation of non-native species in the population of non-salmonids to comply with Oregon's Order. WADOE's Rule Implementation Plan is unchanged and continues to require GBT evaluation of native non-salmonids.

The terminology that has been adopted to refer to the States' TDG Water Quality Standards (WQS) is the "gas cap." Gas cap spill is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state law. In its implementation of spill for fish passage, the Corps will operate its fish passage projects in 2025 to the spill levels identified in the CRSO EIS ROD, 2020 CRS BiOps, and Appendix B of the USG Commitments as extended and modified, and in accordance with the States' TDG standards described above, including applying the different state calculation methodologies. When the standards vary or conflict, the Corps will apply the more stringent standard.

2.2. Spill Caps

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing conditions to manage TDG within all applicable State standards. To accomplish this, the RCC determines "spill caps" for each of the Corps' lower Columbia and lower Snake River projects daily throughout the fish passage spill season. Spill caps are the maximum spill level at each project that is estimated to meet, but not exceed, the gas cap.

To calculate spill caps, the Corps evaluates observed and forecasted variables that influence TDG levels, including: (1) environmental conditions (e.g., total flow, wind, ambient temperature, barometric pressure, and incoming TDG from upstream); and (2) project operations (e.g., spill level, spill pattern, tailwater elevation, proportion of flow through the turbines, and project configuration).

During spill for fish passage, the Corps reviews spill caps daily and adjusts as necessary to define the maximum spill level that maintains TDG within applicable State standards. Additional information about how the Corps will manage TDG is described in the 2025 Water Management Plan (see Appendix 4: TDG Management Plan)[7].

Higher spill than the target spill levels identified in Tables 3, 4, and 5 may occur due to high river flow that exceeds powerhouse hydraulic capacity or due to a lack of power demand (load). During periods when spill is greater than the spill cap due to lack of load conditions, the Corps manages excess TDG on a system-wide basis by incrementally increasing spill at projects

[7] The Water Management Plan (WMP) and associated appendices are updated annually. *See* https://public.crohms.org/tmt/documents/wmp/.

throughout the system in the order of priority defined in the Spill Priority List[8]. For this purpose, the RCC also defines spill rates to target multiple TDG levels in project tailraces that exceed the gas cap. The order of priority is coordinated with regional sovereigns in the Technical Management Team (TMT) to allocate spill to projects to best manage system TDG while also considering how best to protect fish and other aquatic biota.

3. SPILLWAY OPERATIONS AND SPILL LEVEL PRECISION

The Corps plans to achieve the target spill levels defined in Tables 3, 4, and 5 to the extent feasible; however, actual hourly spill levels at each dam may vary depending on the precision of the spillbay gate settings, real-time fluctuations in flow and/or project head, or automatic load following. At each project, spill is distributed across the spillway according to patterns defined in the project-specific chapters of the FPP[9] to provide favorable fish passage conditions.

Spillbay gates are opened to the settings identified in the FPP spill pattern table that correspond to the spill level that is closest to the target but may be slightly higher or lower than the target spill level. Due to these physical limitations in spill level precision, the observed hourly average spill level may vary ±2 kcfs when the target spill is a flow rate (e.g., kcfs) and ±1% when the target spill is a percentage. Not all projects are able to achieve this level of precision (e.g., Little Goose and Bonneville dams). Additional flexibility for balancing reserves (±5%) could occur at John Day Dam (spring and summer) and The Dalles Dam (summer) as identified in Appendix B of the USG Commitments. More information regarding project-specific spill precision limitations may be found in Section 9 below.

Snake River projects make spillbay gate setting changes as soon as feasible in response to target spill changes; however, there may be instances when spill level changes are delayed by up to 1 hour or more due to operation of the navigation locks.

4. MODIFICATIONS TO PLANNED OPERATIONS AND IN-SEASON MANAGEMENT

For planning purposes, the operations described in the 2025 FOP assume average runoff conditions. Actual runoff varies in magnitude and timing and observed river flow may be higher or lower than average at any time such that modifications to the planned operations may be required. To accommodate these varying runoff conditions and other routinely observed conditions as they arise, the Corps, in conjunction with the other Action Agencies, NMFS, and USFWS, coordinates with regional sovereigns on these conditions and other planned operations through the review of the 2025 FOP prior to spring spill operations (see section 4.1). The Corps responds in real-time to these routine conditions and planned operations by implementing adjustments as conditions require without additional coordination.

For unanticipated and unplanned conditions that are not pre-coordinated, the Corps responds as necessary to adjust to the condition, and when possible, will use the existing regional

---

[8] Spill Priority List: https://public.crohms.org/tmt/documents/spill-priority/
[9] The FPP is coordinated annually with regional sovereigns through the FPOM. *See* https://public.crohms.org/tmt/documents/fpp/.

coordination process[10] to adaptively manage and make necessary in-season adjustments in spill and other fish operations (e.g., spill levels, spill caps, spill patterns, juvenile fish transportation, and pool operating ranges).

4.1. Conditions that May Require Adjustments to Planned Operations

Under certain conditions or circumstances, the Corps may be required to adjust spill higher or lower than the target spill level at one or more projects.

Planned and Routine Operational Adjustments:[11]

1. High flow conditions that exceed powerhouse hydraulic capacity and require spilling more than the target spill level.
2. Low flow conditions that require adjustments in spill level while maintaining project minimum generation requirements (see section 4.3.1. below).
3. Lack of power demand (load) resulting in increased spill.
4. Operational limitations, for example physical limitations of gate settings, spill patterns (see section 3), forebay elevation, and deadband[12].
5. Scheduled turbine unit and/or transmission outages that reduce powerhouse hydraulic capacity and require spilling more than the target spill level.* (see footnote 11)
6. Standard operations for transmission reliability (see section 4.4.1. below).*(see footnote 11)
7. Navigation safety concerns (see section 4.6. below).* (see footnote 11)
8. Transition periods between gas cap spill and lower spill rates (e.g., during performance standard spill blocks[13]) may result in actual hourly spill levels that are slightly higher or lower than targeted spill levels.

Non-routine or Unplanned Operational Adjustments:[14]

1. Contingency operations for transmission reliability (see section 4.4.2 below).

---

[10] In-season adaptive management changes in spill levels could include adjustments that address unintended biological consequences caused by spill (e.g., adult passage delays), for the juvenile fish transportation program, for research activities for studies to evaluate fish passage facilities, survival, or other fish-related issues. Spill patterns and biological testing protocols that have not been coordinated to-date will be considered through the regional coordination process using Regional Forum subcommittees, which include the TMT, Studies Review Workgroup (SRWG), Fish Facility Design Review Work Group (FFDRWG), and FPOM.

[11] Planned and Routine Operational Adjustments are spill adjustments due to (1) conditions that occur routinely every year (e.g., high or low flow), or (2) planned operations (e.g., scheduled maintenance, transit of fish transport barge in the tailrace). These are considered pre-coordinated through regional sovereign review of the FOP and the FPP and are implemented by the Action Agencies as conditions require and without additional coordination through the regional forum processes. Spill adjustments due to routine or planned operations are included in the monthly FOP Implementation Report in the hourly spill and flow charts (plots), and conditions with an (*) are reported in the "Pre-Coordinated Operations" Table. The FPP (Appendix A) identifies actions with pre-coordinated dates.

[12] Deadbands occur when turbine outflow cannot achieve some flow ranges. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows.

[13] "Performance standard" spill is a NMFS term and refers to spill levels intended to meet NMFS' performance standard testing, as described in the 2008 Biological Opinion and accompanying administrative record.

[14] Spill adjustments that occur due to non-routine or unplanned conditions or operations are implemented by the Action Agencies as conditions require and/or as coordinated with regional sovereigns through the in-season adaptive management process. Non-routine or Unplanned Operational Adjustments that affect spill levels are reported in the

2. Fish emergencies (e.g., high river temperatures that exceed levels safe for fish, adult fish passage blockages, actionable incidence rates of gas bubble trauma (GBT) incidence rates in either juvenile salmonids or non-salmonids[15], etc.).
3. Conditions related to project safety (e.g., erosion), health and human safety, navigation, or other unforeseen events that require spilling more or less than the target spill level.[16]
4. Other circumstances including human or programming error, unscheduled maintenance or outage, and other unanticipated events or emergencies.
5. In-season adjustments following adaptive management coordination through the existing regional coordination process (see section 4).

4.2. TMT Emergency Protocols

The Corps and the other Action Agencies operate the fourteen Columbia River System projects in emergency situations in accordance with the 2025 Emergency Protocols (WMP Appendix 1 – available online at https://public.crohms.org/tmt/documents/wmp/). This protocol identifies the process the Action Agencies, in coordination with NMFS and USFWS, use in the event of an emergency concerning project operations that impact planned fish protection measures. The emergency protocols also address the process for coordination with regional sovereigns.

4.3. Low Flow Operations

4.3.1. Minimum Generation

All lower Snake and lower Columbia River dams have a minimum generation requirement that has been established to support power system reliability (see section 4.4.). The Corps has identified minimum generation powerhouse outflow values derived from the lower limit of the ±1% peak efficiency operating range defined in the project-specific chapters of the FPP and from actual generation records (see Table 1). Values stated in Table 1 are approximate ranges that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

FOP Implementation Report Variance Table (and when warranted, a description may also be included in the Operational Adjustments section). When a Non-routine or Unplanned Operational Adjustment does not affect spill levels, information about this is provided in the Operational Adjustments section. If an adjustment continues into the next month, the adjustment is reported in the Pre-Coordinated Operations Table.

[15] *See* WAC 173-201A-200(1)(f)(ii)(B)(III), including WADOE's Rule Implementation Plan for Chapter 173-201A WAC Water Quality Standards for Surface Waters of the State of Washington (Publication 19-10-048; pages 7-9), and *Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5, including clarifications from Oregon Department of Environmental Quality email dated 18 January 2023, RE: Request for Clarification of Spring Non-Salmonid Monitoring Requirement.

[16] When a generator requires repair, ongoing operations may require modification to prepare a turbine unit for the necessary maintenance without further damaging infrastructure or jeopardizing personnel safety. To safely install taillogs in a unit adjacent to the spillway, it may be necessary to cease spill through some spillbays for up to 6 or more hours during the installation of the physical barriers to isolate the area and subsequently dewater the draft tube environment. An alternate spill pattern for use during the maintenance period using the remaining spillbays will be coordinated through FPOM.

1. Varying reservoir elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor deadband: the governor controls the number of megawatts the unit should generate but cannot precisely control a unit flow; variations may be 1-2% or more of unit flow. These variations can affect minimum generation ranges in Table 1.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase or decrease flow and generation within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only, not flow through individual turbine units.

All of the lower Snake River powerhouses may be required to keep one generating unit[17] online at all times for power system reliability under low river flow conditions, which may result in a reduction of spill at that project if there is insufficient flow in the river. Generally, units 1–3 are the priority units for operation during the fish passage season for adult fish attraction flow to the fish ladders, but unit priority is also based on availability. During low river flow conditions, the Corps operates the lower Snake River and lower Columbia River projects to the unit priority order specified in the FPP and minimum generation ranges identified in Table 1.

[17] Two generating units may be necessary at Ice Harbor Dam during elevated air temperatures to meet transmission requirements.

Table 1.— Minimum generation flow ranges (kcfs) for turbine units at Corps hydropower projects on the lower Snake and lower Columbia rivers.[18]

Project	Turbine Unit	Minimum Generation Flow Range[A] (kcfs)
Lower Granite	1, 3	11.6 – 12.7
	2[B]	17.8 – 18.8
	4, 5, 6	13.8 – 14.9
Little Goose	1, 2, 3	11.8 – 12.3
	4, 5, 6	14.3 – 14.9
Lower Monumental	1, 2, 3	11.7 – 12.9
	4, 6	13.8 – 14.6
	5[B]	17.8 – 19.0
Ice Harbor	1[C]	Out of service
	2	12.1 – 14.1
	3	8.6 – 10.3
	4[B]	12.2 – 13.5
	5, 6[B]	12.5 – 14.1
McNary	N/A	50 – 60 (may increase up to 80 for reserves)[D]
John Day	N/A	50 – 60 (may increase up to 80 for reserves)[D]
The Dalles	N/A	50 – 60
Bonneville	N/A	30 – 40 (may increase to 60 for reserves)[D]

A. "Minimum Generation" is the minimum number of megawatts (MW) that must be generated at each project to support power system reliability. This table defines the resulting flow range (kcfs) through turbines, which is a function of power output (MW), turbine efficiency, and project head.
B. Lower Granite Unit 2, Lower Monumental Unit 5, and Ice Harbor units 4, 5, and 6 are restricted due to fixed-blade (non-adjustable) runners that are set at a fixed angle (non-adjustable). If a unit is restored to an adjustable-blade Kaplan in-season, the minimum generation range will revert to the lower 1% limit.
C. Ice Harbor Unit 1 is being rebuilt with an adjustable-blade runner design that reduces impacts to fish, scheduled for completion in 2026. At that time, testing will be performed to confirm the operating range.
D. Powerhouse outflows may increase for reserves up to 80 kcfs at McNary Dam during spring and summer months, up to 80 kcfs at John Day Dam during spring months and up to 60 kcfs at Bonneville Dam during spring months (without triggering reporting requirements described in Section 4.1). Increased powerhouse generation allowances will allow for additional generation for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, the higher ranges will be utilized for reserves under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere (e.g., Grand Coulee and Chief Joseph dams to carry and deploy reserves) has been maximized. Powerhouse flows exceeding 80 kcfs at McNary and John Day dams or 60 kcfs at Bonneville Dam for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table. Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report (see section 10).

There may be situations when river flows are insufficient to maintain minimum generation in Table 1 and the target spill level identified in Tables 3, 4, and 5 every hour. Under these conditions, the lower Snake River projects operate one turbine unit at minimum generation and spill the remainder of outflow. The lower Columbia River projects also operate at minimum generation and pass the remaining outflow as spill down to minimum spill levels. Under low river flow conditions during spring spill operations, the Corps attempts to remain as close as

[18] The table is accurate as of March 2025 but may change in-season as coordinated through FPOM (see the FPP).

possible to spill target levels for either gas cap spill or other spill percentages or volumes, depending on which operation is targeted for a given hour. The inability to meet the target gas cap spill level due to low river flow does not preclude the ability of the Corps to target performance standard spill levels as specified in Table 4. Additionally, inflow provided by non-Federal projects upstream is often variable and uncertain, and in combination with low flow conditions, may result in instances where forebay elevations go outside of the restricted operating ranges for Snake River and Columbia projects described in Section 4.6.[19]

4.3.2. Navigation Lock Operation During Low Flows

At projects that have a target spill level that is a percentage of total outflow, emptying the navigation lock during low flow conditions may temporarily result in a reduced percentage of outflow that is reported as spill. During this time, the spill rate remains constant, but the spill reported as a percent of total outflow may be temporarily reduced below the target percentage. This occurs because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total project outflow than during periods of higher flow.

4.4. Operations for Transmission System Reliability

In managing the fish passage spill operations, the Corps and Bonneville plan to allocate generation and spill at the eight Corps projects on the lower Columbia and Snake rivers in accordance with the 2025 FOP. Periodically, to ensure the reliability of the transmission system when system conditions warrant, it is necessary to increase or decrease the amount of water flowing through a project's turbines and spillbays at one or more of these projects.

Consistent with past practice, if any of the transmission system conditions listed below are present and can be alleviated by temporarily modifying generation levels at one or more federal projects, the Action Agencies adjust generation and spill levels to avoid the transmission system impact. These events could result in actual spill being temporarily higher or lower than the target fish passage spill level. Such events may occur coincident with the transmission system event or in subsequent hour(s) should the event impact water balance at a specific hydro project or river reach. The Corps and Bonneville work to restore conditions to support target spill operations as soon as practicable. These actions are taken to minimize the risk and/or scope of a transmission system emergency and are reported in the monthly FOP Implementation Report (see section 10 below).

4.4.1. Standard Operations for Transmission Reliability

Consistent with past practice, the Action Agencies manage the fourteen Columbia River System projects to be prepared to provide electric reliability support as follows:

[19] Lower Snake River projects operate within the minimum operating pool (MOP) range during fish passage season (Table 2).

1. Ensuring sufficient range of generation capability is available to provide the Bonneville balancing authority[20] area with contingency reserves required by North American Electric Reliability Corporation (NERC) reliability standards.[21]
2. Ensuring generation is available to increase or decrease to balance load and generation within the Bonneville balancing authority area to support reliability.
3. Ensuring enough generating units are online and have sufficient capability to increase or decrease generation to meet the Bonneville balancing authority area frequency response obligations, consistent with reliability standard requirements.
4. Bonneville must first meet its reserve obligations for system reliability.[22] When conditions result in an inability to meet the target spill levels defined in Tables 4 and 5, Bonneville will make best efforts to minimize the allocation of reserves (decremental, DEC and/or incremental, INC) on fish passage projects if a spill reduction would be required to allocate the reserves.
5. Ensuring that there is generation operating at projects in specific locations sufficient for arming for Remedial Action Schemes (RAS).[23] RAS allow the transmission system to automatically respond to unplanned events on the power system by immediately dropping or reducing generation at those specified locations.
6. Maintaining minimum generation levels (see Table 1) at generators in specific locations to maintain correct voltage levels on the power system to ensure reliability.
7. Maintaining enough generation units online in diverse locations on the electrical grid to ensure system stability through rotating inertia.

4.4.2. Contingency Operations for Transmission Reliability

If the routine reliability tools described above are insufficient to resolve the transmission condition, the Action Agencies implement the preemptive actions detailed in the Power System Emergency Action Plan (Attachment 1 to the TMT Emergency Protocols referenced in section 4.2 above) if time permits. Where necessary, the fourteen Columbia River System projects will be called upon to relieve the following conditions:

1. Increasing or decreasing generation at projects (redispatch) in specific geographic locations to relieve heavily loaded transmission lines if required by system conditions. This includes adjusting generation that flows over specific transmission facilities to keep flows over those paths within the requirements of NERC reliability standards.
2. Increasing or decreasing generation to ensure transmission system stability and/or reliable load service in local areas under specific system conditions. For example, increasing

[20] A balancing authority is the responsible entity that maintains load-interchange-generation balance within a Balancing Authority Area and supports interconnection frequency in real time. Balancing authority area is the collection of generation, transmission, and loads within the metered boundaries of the designated balancing authority. The balancing authority maintains load-resource balance within this area.
[21] The Federal Energy Regulatory Commission has certified the NERC as the Electric Reliability Organization responsible for establishing and enforcing national reliability standards.
[22] For example, generators may be required to maintain generation levels above minimum generation to provide sufficient capability to reduce generation.
[23] Remedial Action Schemes are sets of automatic control circuits that switch various types of power system components on or off in response to disturbances on the interconnected transmission system.

generation at Ice Harbor Dam to support transmission stability, including providing load service to the Tri-Cities area of Washington, when system conditions require.
3. Responding to unanticipated significant events, including NERC Energy Emergency Alerts or other system emergencies, consistent with the Power System Emergency Action Plan included as Attachment 1 to the TMT Emergency Protocols.
4. Other unanticipated significant events (e.g., fires, earthquakes, etc.).

These actions are implemented consistent with the TMT Emergency Protocols (see section 4.2 above).

4.5. Turbine Unit Testing for Maintenance

Turbine units may be operationally tested prior to maintenance and prior to return to service by running the unit at speed no load, various loads within the ±1% of peak efficiency range, and, if necessary, up to full load, to allow for measurements and testing. Testing of a unit under maintenance is in addition to a unit operating at minimum generation required for power system reliability. Testing may deviate from unit operating priorities specified in FPP Chapters 2-9 and may use water that would otherwise be used for spill if the unit operating for reliability is at the bottom of the ±1% of peak efficiency range. Water is used from the powerhouse outflow allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps coordinates this testing with the region through FPOM. Unit outages for required maintenance are described in FPP Appendix A. Maintenance dates are subject to change.

4.6. Navigation Safety and Minimum Tailwater Elevations

Short-term adjustments in spill or minimum operating pool (MOP) elevations may be required at any of the fish passage projects to address navigation safety concerns.[24] This may include changes in spill patterns, reductions in spill, short-term spill curtailment, or operating above MOP. Adjustments to MOP may also be required to meet minimum tailwater elevations (Table 2). Current spill operations for fish passage result in complex downstream hydraulics that cause large fluctuations in tailwater elevations. The 2020 BiOps describe MOP at the lower Snake River projects as a 1.5-foot range above the minimum forebay elevation (Table 2). To clearly communicate the implementation of this operation, the term "MOP" will refer to the 1.5-foot operating range above the minimum forebay elevation at the lower Snake River projects (i.e., "MOP" is a 1.5-foot operating range).

The Corps will operate Lower Granite Dam at MOP with a 1.5-foot forebay operating range and a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint") from April 3 until August 31, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.[25] Little Goose, Lower Monumental and Ice Harbor dams will operate at MOP with a 1.5-foot forebay operating range and a 1.0-foot range soft constraint to

[24] The Corps conducts annual surveys to assess sedimentation in the reservoirs and under certain conditions. To ensure safe navigation, there may be a need to operate the pools above the MOP range.
[25] The Corps conducts a bathymetric survey of the federal navigation channel annually to assure a 14-foot depth is maintained in the federal navigation channel. With the dredging completed in winter 2022/2023, Lower Granite will operate in the normal MOP range (733.0-734.5 feet) from April 3 until August 31 (and within a 1.0-foot soft constraint range to the extent possible).

the extent possible from April 3 until August 14, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.

Table 2.— Normal and minimum operating pool (MOP) elevation ranges and minimum tailwater elevations for lower Snake River projects. [A]

Project	Normal Operating Elevation Range (ft)[B]		MOP Elevation Range (ft)[C]		Project Tailwater (ft)
	Minimum	Maximum	Minimum	Maximum	Minimum
Lower Granite	733.0	738.0	733.0	734.5	633.0
Little Goose	633.0	638.0	633.0	634.5	537.0
Lower Monumental	537.0	540.0	537.0	538.5	437.0
Ice Harbor	437.0	440.0	437.0	438.5	337.0

A. Elevations provided in feet above mean sea level (NGVD29).
B. August 15 – April 2, except at Lower Granite (September 1-April 2).
C. April 3 – August 14, except at Lower Granite (April 3 – August 31). Projects will be operated within a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint").

Potential in-season adjustments to MOP, if necessary, will be an expanded forebay operating range (Expanded MOP) or raised minimum forebay elevation (Raised MOP), as described below.

Expanded MOP: If the 1.5-foot MOP range is insufficient to maintain navigation safety, the range is expanded (e.g., to 2 feet). For instance, some flow conditions may require a 2-foot forebay operating range at Ice Harbor to provide safe conditions for barge traffic at the navigation lock exit. These adjustments may be necessary for both commercial traffic and fish transport barges. Using Ice Harbor as an example, this type of adjustment would be described as "2-foot expanded MOP (437.0-439.0 feet)". Additionally, large within day fluctuations between gas cap spill and spill percentages or prescribed volumes may cause operational challenges in meeting MOP and an expanded MOP may be necessary, especially when combined with restricted turbine units that are not able to operate in the full ±1 percent range.

Raised MOP: If the minimum forebay elevation is insufficient to maintain navigation safety or meet project minimum tailwater elevations, the 1.5-foot MOP range is raised as necessary. Adjustments in MOP operations have been necessary at the lower Snake River projects, typically during lower flow conditions. For instance, low flows in combination with fish passage spill operations may impact reservoir elevations and cause dips below project minimum tailwater elevations or inadequate navigation depths. Using Little Goose as an example, this type of adjustment would be described as "1.5-foot raised MOP (634.5-636.0 feet)".

Spill Adjustments: High spill levels may create unsafe hydraulic conditions for commercial, non-commercial, and fish transportation barges entering and exiting the tailrace and/or while moored at the fish transport loading facility. Under these conditions, spill may be reduced temporarily as necessary to maintain safe navigation conditions for commercial, non-commercial, or fish transportation barges, which may result in temporarily filling the pool above the MOP range, depending on river flow.

5. JUVENILE FISH TRANSPORTATION PROGRAM

The best available information will be considered in the Corps' implementation of the juvenile fish transportation program operations at the Snake River collector projects in 2025. Should regional sovereigns recommend adjustments in transportation start dates that differ from those stated herein, the Corps uses the existing regional adaptive management process to reconcile recommended operational adjustments.

The following describes the proposed transportation operations for the lower Snake River projects. Detailed descriptions of project and transport facility operations to implement the juvenile fish transportation program are contained in the FPP Appendix B.

5.1. Lower Snake River Dams – Transport Operation and Timing

Transportation will be initiated at Lower Granite, Little Goose and Lower Monumental dams on April 24 (collection starting on April 23) or as coordinated through the TMT and the RIOG but begin no later than May 1. Transport begins the following day after fish collection and collected juvenile fish will be transported from each facility on a daily or every-other-day basis (depending on the number of fish) throughout the migration season. Transportation of spring migrants ends on June 20. Truck transportation of summer migrants at Lower Granite and Little Goose resumes on August 1 with allowance for TMT adaptive management adjustments and continues through October 31. Transportation operations are carried out at each project in accordance with relevant FPP operating criteria. Transportation and spill operations may be adjusted due to research, conditions at fish collection facilities (e.g., overcrowding or temperature extremes), or through the adaptive management process with FPOM and/or TMT (e.g., to respond to expected environmental conditions, to respond to recent transport vs in-river research results, to better match juvenile outmigration, or to achieve/maintain spill targets).

5.2. Transport Research – Seasonal Effects of Transport

An ongoing annual study will be conducted again in 2025 to determine seasonal effects of transporting fish from the Snake River to optimize a transportation strategy. Fish will be collected for this study at Lower Granite starting on April 14, with marking beginning on April 15.

Depending on the number of fish available, fish will be collected 1-2 days each week with tagging occurring on the day following collection. A barge will leave on Thursday (17 April) morning with all fish collected during the previous 1-2 days (excluding fish tagged for in-river survival, which will be released into Lower Granite Dam tailrace). If necessary to achieve the proper loading density, additional fish will be collected on 16 April (but not tagged). By barging all fish (minus the in-river group) during 1 to 3 days of collection, barge densities are expected to be maintained similar to what would occur under normal transport operations at that time of year. This pattern will occur the week preceding general transportation and will be incorporated into general transportation once that operation begins. The desired transported sample size is 6,000 wild Chinook, 4,000-6,000 wild steelhead, and 4,000-6,000 hatchery steelhead weekly for approximately five to six weeks.

6. FALL/WINTER SURFACE SPILL OPERATIONS

Surface spill operations in March–April and September–November (referred to in Appendix B of the USG Commitments Document as "Fall/Winter Spill Operations") will occur during the dates and times defined below in Table 3. Surface spill will occur via the project's spillway weir (RSW, TSW, or ASW[26]), except at The Dalles and Bonneville dams which do not have a spillway weir and will instead operate non-spillway surface passage routes as defined in Table 3.

Table 3.— Fall/Winter Surface Spill Operations.[A]

Project	Dates	Hours	Notes
LWG, LGS, LMN, IHR, MCN	March 1 – March 20	4 hours/day in the morning, 7 days/week	LGS ASW in high crest (~7 kcfs). MCN TSW in spillbay 20.
	March 21 – April 2 (Snake projects) / April 9 (MCN)	24 hours/day, 7 days/week	
	September 1 – November 15	4 hours/day in the morning, 7 days/week	
JDA	March 21 – April 9	24 hours/day, 7 days/week	Opening the JDA TSW requires a crew and crane and must be done during daylight hours. On March 21, an equivalent spill rate (~10 kcfs) will occur via the non-TSW pattern from 0001 hours until the TSW in spillbay 19 is opened in the morning as early as possible.
TDA Sluiceway	March 1 – December 15	24 hours/day, 7 days/week	TDA sluiceway is a non-spillway surface passage route. See FPP Chapter 3 for operating criteria.
BON B2CC	March 1–8	0600-1000 daily	BON PH2 corner collector (B2CC) is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.
	March 9–25	0600-1000, 1600-2000 daily	
	March 26 – August 31	24 hours/day, 7 days/week	
BON Sluiceway	Year-round	24 hours/day, 7 days/week	BON PH1 sluiceway is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.

A. Spill may be temporarily reduced below the FOP target spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.

7. SPRING FISH PASSAGE SPILL OPERATIONS

Spring spill operations occur April 3–June 20 at the four lower Snake River projects, and April 10–June 15 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for spring 2025 at each project are defined in Table 4. If deleterious impacts of the proposed spill operations are observed in-season, existing adaptive management processes may be employed to address the

[26] Depending on their design, spillway weirs are referred to as either "Removable" (RSW–applies to LWG, LMN, IHR), "Adjustable" (ASW–applies to LGS), or "Top" (TSW–applies to MCN and JDA).

cause of the impacts. Spill may be temporarily reduced at any project to ensure navigation safety or transmission reliability. In order to operate consistently with state water quality standards, spill may also be reduced if observed GBT levels exceed those identified in state water quality standards (*See* WASH. ADMIN. CODE § 173-201A-200(l)(f)(ii)(B)(III) and *Order Approving a Modification to Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5).

Spill up to the 125% gas cap is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state laws. This includes a criterion for not exceeding 126% TDG for the average of the two greatest hourly values within a day.

Table 4.— Summary of 2025 spring target spill levels at lower Snake River (April 3 – June 20) and lower Columbia River (April 10 – June 15) projects.

PROJECT	SPRING SPILL DATES	SPRING SPILL OPERATION
Lower Granite [A, C]	April 3 - June 20	24 hours/day: 125% Gas Cap
Little Goose [B, C]	April 3 – June 20	125% Gas Cap 24 hours/day (until adult criteria met) *then* 16 hours/day: 125% Gas Cap; 8 hours/day: 30% of outflow (Performance Standard)
Lower Monumental [A]	April 3 - June 20	24 hours/day: 125% Gas Cap
Ice Harbor	April 3 – June 20	24 hours/day: 125% Gas Cap
McNary	April 10 – June 15	24 hours/day: 125% Gas Cap
John Day [D]	April 10 – June 15	Daytime hours: 40% of outflow; Nighttime hours: 125% Gas Cap
The Dalles [E]	April 10 – June 15	24 hours/day: 40% of outflow (Performance Standard)
Bonneville [F]	April 10 – June 15	24 hours/day: 125% Gas Cap

A. Lower Granite and Lower Monumental Adult Delay Criteria – See Section 7.1.
B. Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2025, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000.
C. During periods of high river flow that exceeds powerhouse hydraulic capacity, implementing 8 consecutive hours of spill as described in Footnotes A and B may result in storing additional inflow in the forebay above MOP. If it is necessary to pond water to achieve the 8-hour block of spill during high inflow, water stored above MOP should be drafted out over the remaining hours by increasing spill to pass inflow from 1200-1600 hours, then increasing spill as necessary from 1600-0400 to draft the pool back to MOP. If it is forecasted that the drafting spill will result in exceeding 130% TDG in the tailrace, all 16 hours will be used to return the pool to MOP. In lack of load conditions performance standard spill blocks will be prioritized at Little Goose, Lower Monumental, and Lower Granite dams, in that order.
D. John Day Dam – Daytime hours are defined in FPP Chapter 4, Table JDA-5. Daytime hourly spill target of 40% river flows with ±5% flexibility in river flow for balancing reserves, consistent with current target spill level calculations.

E. The Dalles Dam –TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.
F. Bonneville Dam – Spill for fish passage should not exceed 150 kcfs due to erosion concerns.

7.1. Adult Migration Delay Protocol for Spring Spill Operations at Lower Granite and Lower Monumental Dams

Lower Granite and/or Lower Monumental daytime spill levels will be decreased to 40% of project outflow for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) when adult delay or passage issues are observed at both/either of these projects. An adult delay or passage issue occurs when the following three criteria are met: (1) *fewer than* 50% of the single departure event per tag ID of PIT-tagged adult spring/summer Snake River Chinook detected at the downstream project (i.e., Ice Harbor or Little Goose dams) arrive at the upstream project (i.e., Lower Monumental or Lower Granite dams) within 3 days and this pattern persists for 4 consecutive days,[27] (2) a running 3-day minimum of 7 PIT-tagged adult spring/summer Snake River Chinook are detected at the downstream projects,[28] and (3) if the upstream dam's average outflow was below 160 kcfs each day of the delay. If all three criteria are met, the Corps will implement a 40% daytime spill operation (adult daytime spill operation) for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) on the next calendar day and continue for 3 consecutive days. Based on the availability of information on the three criteria, the adult 40% daytime spill operation may begin as early as day 5 and no later than day 6. Consistent with past operations to reduce spill at Little Goose Dam, if lack of load conditions preclude the implementation of 40% spill to begin between 0400-0800, reduced spill will occur as soon as practicable during morning hours and continue for up to 8 consecutive hours. If 8 hours of consecutive spill at 40% was not feasible, a second block will start as soon as load conditions allow, continue for at least two consecutive hours, and will conclude no later than 2000 (see Table 4, footnote B).

Assuming *greater than* 50% of the single departure event per tag ID of PIT-tagged adults arrive at the upstream project by day 3 then standard operations (125% TDG spill 24/7) would be reinstated the calendar day after information becomes available, as early as day 4 and no later than day 5. If greater than 50% of the daily cohort does NOT arrive at the upstream project by day 3 and project average flow was below 160 kcfs, adult daytime spill operations would continue an additional day and would be evaluated again the following day as previously described. This would continue until the adult delay or passage issue has been resolved and the standard operations can be reinstated as described in Table 4.

---

[27] The return to 125% TDG spill 24/7 will be triggered if 50% or more of the running 3-day cohort for the most recent day (e.g., day 3 of adult daytime spill) is detected at the upstream dam. The agencies will use Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool for this purpose.
[28] The agencies will use the current Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool ("Running 3-day DART tool") to determine if criteria one and two have been met. See top panel, in-season graphics of Cumulative Arrival Percent by Days in Route to Lower Granite or Lower Monumental dams. https://www.cbr.washington.edu/dart/query/pitadult_reachdist

The TMT may consider in-season deviations from these criteria if unforeseen factors are reasonably expected to cause substantial delay (e.g., lack of load conditions, priority turbine unit outages, etc.) and the Fish Passage Operations and Maintenance (FPOM) Coordination Team may consider refinements to these triggers following each spring spill season.

8. SUMMER FISH PASSAGE SPILL OPERATIONS

Summer spill operations occur June 21–August 31 at the four lower Snake River projects, and June 16–August 31 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for summer 2025 at each project are defined in Table 5. At the Snake River Projects spill may ranges up to ±1 kcfs during the summer spill operation from August 1 – August 31.

Table 5.— Summary of 2025 summer target spill levels at lower Snake River and lower Columbia River projects.

PROJECT	EARLY SUMMER SPILL[A] (June 21/16 – July 31) (24 hrs/day)	LATE SUMMER SPILL[A] (August 1 – August 31) (24 hrs/day)
Lower Granite [B]	18 kcfs	RSW flow (as river flow allows)
Little Goose [B, C]	30%	ASW flow or 7 kcfs
Lower Monumental [B, D]	17 kcfs	RSW flow or 8 kcfs
Ice Harbor [B, E]	30%	RSW flow or 9 kcfs
McNary [F]	57%	2 TSWs flow or 20 kcfs
John Day	35% [G]	2 TSWs flow [H] or 20 kcfs
The Dalles	40% [G]	30% [G]
Bonneville	95 kcfs	50 kcfs

A. Spill may be temporarily reduced below the FOP target summer spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.
B. Late summer spill August 1-August 31 will be through the spillway weir or a constant spill rate through conventional spillbays using the appropriate FPP spill pattern. The spillway weir spill rate is a function of forebay elevation (as pool elevation increases, more water is spilled over the weir), as defined in the FPP. The spillway weirs will be operated per FPP criteria and closed when low flow criteria are met. When the spillway weir is closed, the spill target will transition to a constant spill rate through conventional spillbays and will not vary with a fluctuating forebay elevation.
C. Flow corresponds to the Little Goose ASW high crest elevation as adjusted relative to the forebay operating range (see FPP Chapter 8, section 2.3.2.7).
D. Flow corresponds to a Lower Monumental forebay elevation of 538.5 feet, the mid-point of the forebay range from 537-540 feet.
E. Flow corresponds to an Ice Harbor forebay elevation of 438.5 feet, the mid-point of the forebay range from 437-440 feet.
F. From June 16-July 31, McNary will adjust spill once a day to 57% of the previous day's average project outflow. The intent is to reduce the frequency of spillgate changes while implementing a more uniform pattern to the extent it can be done safely (see FPP Chapter 5, section 2.2.1.1).
G. Hourly spill percentage target of river flow with ±5% flexibility of river flow for balancing reserves, consistent with current target spill level calculations.
H. John Day will also spill from bay 2 open 1 stop (approximately 1.6 kcfs) during daylight hours when spill is through the TSWs only to maintain attraction flow to the north adult ladder, per FPP Chapter 4 (JDA), section 2.2.3.

9. PROJECT-SPECIFIC OPERATIONS

The following sections describe 2025 spill operations for each project. The Corps implements established spill patterns for all projects as described in the FPP. Additional information regarding spill precision outside these dates may be found in Section 3 above.

9.1. Lower Granite Dam

9.1.1. Fall/Winter Surface Spill (Table 3). The Lower Granite RSW spill rate will increase with increasing forebay elevation, from approximately 5.6 kcfs at the bottom of the normal forebay operating range up to 11.4 kcfs at the top of the range (see FPP Chapter 9, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.1.2. Spring Spill (Table 4): 125% gas cap (see Section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (see Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow, 8 hours/day.

9.1.3. Summer Spill (Table 5):

- June 21–July 31: 18 kcfs, 24 hours/day.
- August 1–31: RSW spill, 24 hours/day.

9.1.4. Operational Considerations: During low flow when spill is less than 15 kcfs and the RSW is open, Lower Granite will transition to alternate spill patterns defined in FPP Table LWG-7-ALT if needed to maintain the tailwater elevation at no lower than 633 feet. The project will switch to these alternate patterns to avoid or minimize the need to raise the Little Goose forebay operating range to keep from dropping below the Lower Granite minimum tailwater elevation.

9.2. Little Goose Dam

9.2.1. Fall/Winter Surface Spill (Table 3). The Little Goose ASW will be adjusted relative to forebay up to once per day to maintain a "high crest" elevation and a minimum of 7 kcfs spill (see FPP Chapter 8, section 2.3.2.7).

- March 1–20: ASW high crest 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: ASW high crest 24 hours/day, 7 days/week.
- September 1 – November 15: ASW high crest 4 hours/day in the morning, 7 days/week.

9.2.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3 until adult criteria are met, then 125% gas cap, 16 hours/day, and 30% of outflow (performance standard) 8 hours/day, through June 20 (Table 3, footnote B).

9.2.3. Summer Spill (Table 5):

- June 21–July 31: 30% of outflow, 24 hours/day (except when adjusted to a constant spill level during low flows, as described in Operational Considerations below).
- August 1–31: ASW spill or approximately 7 kcfs, 24 hours/day.

9.2.4. Operational Considerations:

- When the ASW is closed and project outflow is less than or equal to 38 kcfs, actual hourly average spill levels at Little Goose may range up to ±4% according to the spill patterns in FPP Chapter 8 Table LGS-11.
- During low flow conditions at Little Goose, spill may exceed the target percentage if the ASW is in service, which restricts the project to a fixed minimum spill level (i.e., spill cannot be reduced below the spill rate through the ASW, which may result in spilling more than the target percentage at lower outflows).
- During the 30% spill operation when project outflows are ≤ 32 kcfs, the spill operation will transition from 30% to a constant spill rate of approximately 7-11 kcfs to help stabilize project outflow, meet Lower Monumental target spill levels, and maintain MOP elevation at Little Goose. The constant spill level will be based on the previous day's average total project outflow, as follows: 11 kcfs when total outflow is 28.0 to 32.0 kcfs, 9 kcfs when total outflow is 24.0 to 27.9 kcfs, and 7 kcfs when total outflow is ≤ 23.9 kcfs. Actual spill may range up to ±1 kcfs from the target spill level. Spill changes will be made by 0300 each day.

9.3. Lower Monumental Dam

9.3.1. Fall/Winter Surface Spill (Table 3). The Lower Monumental RSW spill rate will increase with increasing forebay elevation, from approximately 6.7 kcfs at the bottom of the forebay operating range up to 9.5 kcfs at the top of the range (see FPP Chapter 7, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.3.2. Spring Spill (Table 4): 125% gas cap (section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow 8 hours/day. Spring spill will occur using the uniform pattern, except during low

flows (spill below 30 kcfs) when the bulk pattern will be used to avoid small gate openings that could impact fish.

9.3.3. Summer Spill (Table 5):

- June 21–July 31: 17 kcfs (bulk pattern), 24 hours/day.
- August 1–31: RSW spill or approximately 8 kcfs, 24 hours/day.

9.3.4. Operational Considerations: Transit of the juvenile fish barge across the Lower Monumental tailrace, docking, and departure from the collection facility, may require a reduction in spill below the target spill level for safety concerns. The towboat captain may request spill be reduced or eliminated during transit. During juvenile fish barge loading operations, spill is typically reduced to 15 kcfs using the bulk pattern, but can be reduced further, if necessary, for safety reasons. Barge loading duration can be up to 3.5 hours. Reducing spill may cause the Lower Monumental pool to briefly operate outside of MOP elevations.[29]

9.4. Ice Harbor Dam

9.4.1. Fall/Winter Surface Spill (Table 3). The Ice Harbor RSW spill rate will increase with increasing forebay elevation, from approximately 7.1 kcfs at the bottom of the forebay operating range up to 10.4 kcfs at the top of the range (see FPP Chapter 6, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.4.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3–June 20.

9.4.3. Summer Spill (Table 5):

- June 21–July 31: 30%, 24 hours/day.
- August 1–31: RSW spill or approximately 9 kcfs, 24 hours/day.

9.4.4. Operational Considerations:

- When the RSW is open, the minimum project spill level is fixed at approximately 7.1-8.7 kcfs, depending on forebay elevation (i.e., spill cannot be reduced below the fixed volume through the RSW). This operational limitation results in spilling more

[29] With spill levels in spring 2025 targeting the gas cap for at least 16 hours/day, reducing spill at Lower Monumental for long durations could pose problems for staying within MOP at Ice Harbor Dam, the next downstream project.

than 30% when total outflow drops below approximately 28 kcfs. Per FPP section 2.3.2.7, the RSW is closed when day average outflow is below 30 kcfs and forecasted to stay below 30 kcfs for at least 3 days. However, outflow may drop below 28 kcfs on an hourly basis while the RSW is still open, resulting in spill greater than 30% for those hours.

- Currently, all but one of the five available Ice Harbor turbines have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (also referred to as "fixed-blade" or "locked-blade" units). Only Unit 3 has adjustable blades. As a result, turbine outflow cannot achieve some flow ranges, referred to as deadbands. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows. Unit 1 is currently out of service until 2026 to install a new adjustable-blade runner design.

9.5. McNary Dam

9.5.1. Fall/Winter Surface Spill (Table 3). The McNary TSW spill rate will increase with increasing forebay elevation, from approximately 8 kcfs at the bottom of the normal forebay operating range up to 11 kcfs at the top of the range.

- March 1–20: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.
- March 21 – April 9: Spillbay 20 TSW 24 hours/day, 7 days/week.
- September 1 – November 15: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.

9.5.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 10–June 15.

9.5.3. Summer Spill (Table 5):

- June 16–July 31: 57% of the previous day's average outflow, 24 hours/day. Spill changes will be made by 0300 each day.
- August 1–31: Two TSWs spill or 20 kcfs, 24 hours/day.

9.5.4. Operational Considerations:

- Currently, McNary spillbays are restricted due to hoists and cranes that need replacement. As a result, McNary will implement modified spill patterns. For more information, see FPP Chapter 5 (MCN), section 2.2.
- Currently, McNary Dam turbine units 5 and 6 have runner blades that are locked at a set angle (non-adjustable). As a result, the units are restricted to a very narrow ±1% operating range of approximately 10-12 kcfs (see FPP Chapter 5 Table MCN-

6-A) and there may instances when the unit is unable to stay within this restricted range.

9.6. John Day Dam

9.6.1. Fall/Winter Surface Spill (Table 3).

- March 21 – April 9: Spillbay 19 TSW spill 24 hours/day, 7 days/week.
- Opening the TSWs at John Day Dam requires a crew and gantry crane and must be done during daylight hours as weather allows. On March 21, spill will occur at an equivalent rate (approximately 10 kcfs) with the non-TSW pattern in FPP Table JDA-9 from 0001 hours until the TSW is opened in the morning.

9.6.2. Spring Spill (Table 4): 40% of outflow daytime and 125% gas cap nighttime, April 10–June 15, with priority to maintain 40% spill 24 hours/day at The Dalles Dam as needed for TDG management. Daytime hours are defined in FPP Chapter 4, Table JDA-5. A crew will install the TSW in spillbay 18 on the first day of spring spill as early as possible during daylight hours (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

- Daytime 40% of outflow with ±5% flexibility of river flows for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP implementation report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP implementation report.

9.6.3. Summer Spill (Table 5):

- June 16–July 31: 35% of outflow, 24 hours/day with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flows for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.
- August 1–31: Two TSWs or 20 kcfs, 24 hours/day. A crew will close both TSWs on the last normal workday of summer spill, Thursday, August 28, 2025, as late in the day as possible. Spill will be maintained at an equivalent rate of 20 kcfs through midnight on August 31 using the spill patterns with no TSWs (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

9.6.4 Operational Considerations:

- Currently, turbine units 2, 3, 8, 9, 10, 11, and 13 at John Day have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (see FPP Chapter 4 Table JDA-7-A). As a result, the turbines have a restricted operating

range of approximately 17-19 kcfs and may not be able to stay within the narrow 1% turbine band associated with it.

- See the WMP sections 6.11.1.4 and Tables 2 and 5 and Section 6.11.1.3 for discussion of springtime pool elevations to dissuade nesting of Caspian terns at Blalock Island. This operation is also described in the FPP Appendix A. This higher forebay operation will increase the flow rate over the TSWs and may change tailrace flow patterns.

9.7. The Dalles

9.7.1. Fall/Winter Surface Spill (Table 3): The ice & trash sluiceway (ITS) is a powerhouse (non-spillway) surface passage route and will operate March 1–December 15, 24 hours/day, pursuant to criteria in FPP Chapter 3.

9.7.2. Spring Spill (Table 4): 40% of outflow, 24 hours/day, April 10–June 15. Maintain 40% spill 24 hours/day at The Dalles Dam and reduce John Day Dam TDG spill cap as needed for TDG management.

9.7.3. Summer Spill (Table 5):

- June 16–July 31: 40% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.

- August 1–31: 30% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances will be reported in the Variance Table in the monthly FOP Implementation Report.

9.7.4. Operational Considerations:

- Spill bays 9[30], 10, 11, 13, 16, 18, 19, and 23 are operationally restricted due to wire rope, structural and concrete erosion concerns.

9.8. Bonneville Dam

9.8.1. Fall/Winter Surface Spill (Table 3). The PH1 ice & trash sluiceway (ITS) and PH2 corner collector (B2CC) are powerhouse (non-spillway) surface passage routes and will

[30] Spillbay 9 at The Dalles Dam cannot be used due to failure of the trunnion pin in 2009.

operate pursuant to criteria in FPP Chapter 2:

- March 1–8: B2CC daily 0600-1000 hours.
- March 9–25: B2CC daily 0600-1000 and 1600-2000 hours.
- March 26–August 31: B2CC 24 hours/day, 7 days/week (beginning at 0600 on March 26).
- Year-round: ITS 24 hours/day, 7 days/week. From December 15–end of February, the ITS may be closed for up to 6 hours/day for maintenance.

9.8.2. Spring Spill (Table 4): 125% gas cap up to a maximum of 150 kcfs for fish passage spill (see section 2.1), 24 hours/day, April 10–June 15.

9.8.3. Summer Spill (Table 5):

- June 16–July 31: 95 kcfs, 24 hours/day.
- August 1–31: 50 kcfs, 24 hours/day.

9.8.4. Operational Considerations:

- Maximum fish passage spill level is 150 kcfs. This constraint is based on physical model observations indicating an increased incidence of rock deposition into the spillway stilling basin at spill ≥ 150 kcfs, which has caused erosion to the structure in the past.
- Minimum spill level is 50 kcfs; however, as observed in past years, to provide acceptable juvenile fish egress conditions in the tailrace under extreme low flow conditions, lower spill levels may be considered and coordinated through the TMT and/or FPOM.
- Actual hourly average spill levels at Bonneville Dam may range up to ±3 kcfs according to spill pattern tables in FPP Chapter 2.

10. FOP IMPLEMENTATION REPORTING

The Corps posts monthly FOP Implementation Reports between April and August on the following website: https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/. The updates include monthly project plots containing the following information:

- total flow: the total hourly river flow rate;
- generation flow: the hourly flow through the powerhouse turbine units;
- target spill: the spill target for that hour (Tables 3, 4 and 5);
- adjusted spill: the hourly spill level that can be achieved taking into consideration that spill may vary as a function of total river flow, forebay elevation, and generator capacity, and is

subject to routine operational adjustments that limit the ability to spill to the target spill (see section 4.1);
- actual spill: the hourly flow over the spillway; and,
- resultant 12-hour average TDG for the tailwater at each project.

The reports also provide information on non-routine or unplanned operational adjustments that arise during the spill program and address any spill adjustments due to emergency situations (such as unplanned maintenance or outages), and for contingency operations for transmission reliability. See section 4.1 for more information.

The Corps provides the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Hourly flow, generation flow, and spill quantity data for the lower Snake and Columbia River dams are posted to the following website:
    - https://public.crohms.org/report/projdata.htm (web reports with the most recent 8 days of hourly project data and the current month of daily project data).
    - https://public.crohms.org/tmt/wq/historical/ (links to historic hourly project data files in .csv format organized by month back to 2004 including temperature and TDG information).
- Water quality data are received via satellite from TDG Fixed Monitoring Sites (FMS) in the Columbia and Snake rivers every hour and placed on a Corps public website upon receipt. Hourly TDG and water temperature data are posted to the following websites:
    - https://public.crohms.org/report/total.html (web reports with hourly TDG, project outflow and spill for the previous 3 days).
    - https://public.crohms.org/ftppub/water_quality/tdg/ (links to historic hourly water quality data files for each FMS including barometric and total gas pressure, TDG and project outflow and spill in csv-format organized by month back to 2005).
    - Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps calculates both the highest 12-hour average TDG levels (Oregon and Washington spring method) and the highest consecutive 12-hour average TDG levels (Washington summer method) daily. These averages are reported at: https://public.crohms.org/ftppub/water_quality/12hr/.
- Spill cap information is posted to the following site each day: https://public.crohms.org/tmt/documents/ops/spill/caps/.

In addition to the monthly FOP Implementation Reports, the Corps provides status updates at the regularly scheduled TMT meetings about the 2025 fish passage spill operations, including reasonably detailed information that is relevant to the Corps' process for implementing fish passage spill.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-151:
2025 Fish Operations Plan

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, NORTHWESTERN DIVISION
PO BOX 2870
PORTLAND OR 97208-2870

2025 Fish Operations Plan

1. INTRODUCTION

The 2025 Fish Operations Plan (2025 FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish[1] passage at its four lower Snake River and four lower Columbia River dams and includes spring surface spill operations (March through early April), spring and summer spill operations (early April through August), and fall/winter surface spill operations (September through mid-November). The 2025 FOP is consistent with spill operations for fish passage and the regional forum process for adaptive management and in-season management provisions outlined in the Record of Decision for the Columbia River System Operations Environmental Impact Statement (CRSO EIS ROD) dated September 28, 2020, CRSO Final EIS, 2020 National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS) Columbia River System (CRS) Biological Opinions (2020 CRS BiOps)[2], the Extensions of the 2008 Columbia Basin Fish Accords (Accord Extensions), the Corps' requirements under the Endangered Species Act (ESA), and the ongoing consultation and communications with the relevant wildlife agencies to ensure consistency with the Act. The 2025 FOP also incorporates operations outlined in Appendix B of the "U.S. Government Commitments in Support of the Columbia Basin Restoration Initiative" (USG Commitments). The USG Commitments were agreed to as part of the 2023 Memorandum of Understanding (*see* Section 3 of the MOU). Other project operations and water management actions not specifically addressed in this document will be consistent with other guiding operative documents, including the 2025 Water Management Plan (WMP), seasonal WMP updates, and the 2025 Fish Passage Plan (FPP).

In addition to discussing project-specific fish passage spill operations, the 2025 FOP identifies factors that the Corps, the Bureau of Reclamation (Reclamation), and the Bonneville Power Administration (Bonneville) (collectively referred to as the "Action Agencies") must address in the context of operating this complex system of fourteen multiple purpose projects. The 2025 FOP includes a discussion of how the Corps manages fish passage spill and total dissolved gas (TDG), identifies Planned and Routine Operational Adjustments (Section 4) that influence fish passage spill, addresses adaptive management and in-season management processes for fish passage spill and other fish operations including the juvenile fish transportation program, and describes the Corps' monthly implementation reports.

---

[1] ESA-listed salmon and steelhead.
[2] The Corps, in coordination with the other Action Agencies, and NMFS, employs the Regional Implementation Oversight Group (RIOG) and technical teams including the Technical Management Team (TMT) and Fish Passage Operations & Maintenance (FPOM) coordination group, to coordinate with state, tribal and other federal experts for recommendations for implementing operations consistent with the 2020 BiOps.

2. MANAGEMENT OF SPILL FOR FISH PASSAGE AND TDG

2.1. State Water Quality Standards for TDG

The Corps will manage spill for fish passage in 2025 consistent with the State of Washington and the State of Oregon total dissolved gas (TDG) water quality standards (WQS).[3,4] The State of Washington, Department of Ecology (WADOE) adopted a WQS rule change which became effective in 2020 allowing spring juvenile fish passage spill operations to generate specified TDG levels in project tailraces (up to 125% TDG 12 hours, 126% TDG 2 hours), so long as the specified conditions are met, including that spring juvenile fish passage spill operations do not exceed the spill levels and durations reviewed in applicable ESA consultation documents. The Environmental Protection Agency (EPA) subsequently approved the rule change and found that the ESA consultation documents ensure that any spring spill regime using the revised criteria must be performed in accordance with the spill levels and durations evaluated in ESA consultation documents for effects to ESA-listed species of all life stages, including juvenile out-migrating salmonids, resident salmonids, and adult migrating salmonids. EPA's approval of the rule further states that "compliance with the ESA consultation documents is a condition precedent for the revised criteria and so the criteria are not applicable for the purposes of the [Clean Water Act (CWA)] (i.e., have no effect for CWA purposes) without the ESA consultation documents addressing spill operations that result in TDG saturation levels above the pre-existing criterion." *Letter to WADOE from EPA Re: The EPA's Action on Revisions to the [WADOE's] Surface Water Quality Standards for the Site-Specific Total Dissolved Gas Criteria in the Columbia and Snake Rivers, and Other Water Quality Standards Revisions* dated March 5, 2020, page 9.

The State of Oregon, through its Environmental Quality Commission, approved a modification to its TDG WQS of up to 125% TDG from April 1-June15 and up to 120% TDG from June 16-August 31, so long as spring spill is "applied in a manner consistent with the applicable requirements of the federal [ESA]." (*Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem* dated December 31, 2024, page 4). Regarding Oregon's 105% TDG criterion, Oregon Department of Environmental Quality (ODEQ) clarified that this criterion does not apply to the Columbia River per their letter dated January 29, 2024. Both states have thus accommodated levels of TDG above 110% for fish passage spill operations for ESA-listed juvenile salmonids at Corps projects on the lower Snake and lower Columbia rivers, as follows:

---

[3] WASH. ADMIN. CODE § 173-201A-200(l)(f)) provides the maximum TDG criteria for each of the aquatic life use categories and displays Table 200 (I)(f) that states: "Total dissolved gas shall not exceed 110 percent of saturation at any point of sample collection." The code also addresses exceptions and adjustments, including a provision allowing for an adjustment of the TDG criteria to aid fish passage over hydroelectric dams. *See* https://apps.leg.wa.gov/WAC/default.aspx?cite=173-201A-200.

[4] OR. ADMIN. R. 340-041-0031 provides in part: "the concentration of TDG relative to atmospheric pressure at the point of sample collection may not exceed 110 percent of saturation." OR. ADMIN. R. 340-041-104(3) identifies findings the Environmental Quality Commission must make for the purpose of allowing increased spill for salmon migration. *See* https://www.oregon.gov/deq/wq/Documents/columbiaUSACEtmdlorder.pdf

Washington Administrative Code[5]:

WAC 173-201A-200(1)(f)(ii) and WAC 173-201A-200(1)(f)(ii)(A)

(ii) The TDG criteria may be adjusted to aid fish passage over hydroelectric dams that spill for anadromous juvenile fish as of the 2020 spill season. The elevated TDG levels are intended to allow increased fish passage without causing more harm to fish populations than caused by turbine fish passage. The following special fish passage exemptions for the Snake and Columbia Rivers apply when spilling water at dams is necessary to aid fish passage:

(A) TDG must not exceed:

• An average of 115 percent as measured in the forebays of the next downstream dams and must not exceed an average of 120 percent as measured in the tailraces of each dam (these averages are calculated as an average of the 12 highest hourly readings in a calendar day, relative to atmospheric pressure); and
• A maximum TDG saturation level of 125 percent calculated as an average of the two highest hourly TDG measures in a calendar day during spillage for fish passage.

WAC 173-201A-200(1)(f)(ii)(B)

(B) To further aid fish passage during the spring spill season (generally from April through June), spill may be increased up to the following levels as measured at the tailrace fixed site monitoring location:

• A maximum TDG saturation level of 125 percent calculated as an average of the 12 highest hourly TDG measures in a calendar day: and
• A maximum TDG saturation level of 126 percent calculated as an average of any two-consecutive hourly TDG measures. These TDG criteria may be applied in place of (f)(ii)(A) of this subsection during spring spill operations when applied in accordance with the following conditions:

(I) In addition to complying with the requirements of this chapter, the tailrace maximum TDG criteria at hydropower dams shall be applied in accordance with Endangered Species Act consultation documents associated with spill operations on the Snake and Columbia rivers, including operations for fish passage. The Endangered Species Act consultation documents are those by which dams may legally operate during the time that the adjusted criteria in (f)(ii)(B) of this subsection are in use.

(II) Application of the tailrace maximum TDG criteria must be accompanied by a department approved biological monitoring plan designed to measure impacts of fish exposed to increased TDG conditions throughout the spring spill season. Beginning in

[5] The text of the code is copied verbatim below for reference.

the year 2021, plans must include monitoring for non-salmonid fish species and must continue for a minimum of five years, and thereafter as determined by the department.

(III) TDG must be reduced to allowances specified in (f)(ii)(A) of this subsection if the calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of 50 fish required weekly) or non-salmonids (with a minimum sample size of 50 fish required weekly) exceeds:

- Gas bubble trauma in non-paired fins of 15 percent; or
- Gas bubble trauma in non-paired fins of five percent and gas bubbles occlude more than 25 percent of the surface area of the fin.

In accordance with WADOE's Rule Implementation Plan, if gas bubble trauma exceeds these biological thresholds, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be adjusted to allowances specified in this subsection. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above the ability to meet (f)(ii)(B) of this subsection. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of (f)(ii)(B) of this subsection.

Oregon Water Quality Standard Modification:

The Environmental Quality Commission approved the following modification[6] to the statewide standard for total dissolved gas (OAR 340-41-0031(2)) of 110 percent for the lower Columbia River at McNary, John Day, The Dalles and Bonneville dams, as provided for in OAR 340-41-0104(3):

1. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 125 percent for the period from April 1 through June 15.

2. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 120 percent for the period from June 16 through Aug. 31.

3. These limits do not apply when the stream flow exceeds the seven-day, ten-year frequency flood.

4. The modified total dissolved gas standards will apply for five years, beginning Jan. 1, 2025, through Dec. 31, 2029 (calendar years 2025, 2026, 2027, 2028, and 2029).

5. The DEQ Director may approve additional periods of application of this modification up to 120 percent total dissolved gas as calculated in 8.a)i., beyond the April 1 to Aug. 31 period, subject to subsections 8.a) to 8.c) for reasons including passing Spring Creek

[6] The text of the modification is copied verbatim below for reference.

Hatchery fish releases and other voluntary fish passage operations, maintenance activities, and biological or physical studies of spillway structures and prototype fish passage devices. The Corps must notify DEQ in writing at least one week prior to the spill describing the proposed action, including its purpose, and the location and dates of elevated total dissolved gas levels. Spill must be reduced to meet the 110 percent total dissolved gas criterion if requested by the DEQ Director.

6. Application of the tailrace maximum TDG criteria must be accompanied by a DEQ-approved biological monitoring plan designed to measure impacts to fish exposed to increased TDG conditions. Plans must include monitoring for non-salmonid fish species. Gas bubble trauma monitoring may be halted if there is a high mortality risk due to compounded effects of the evaluation procedure and adverse environmental factors such as high stream temperatures.

7. Voluntary fish passage spill during the spring spill season, occurring from April 1 through June 15, is subject to the following conditions:

    a. Spill at a dam must be reduced when:

        i. Instantaneous total dissolved gas levels exceed 127 percent of saturation, calculated as the average of any two consecutive hourly TDG measurements in the tailrace of the dam; or

        ii. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 125 percent.

    b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels to 120 percent as calculated in 8.a)i. when:

        i. The calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of fifty fish required weekly) or non-salmonids (with a minimum sample size of fifty fish required weekly) exceeds gas bubble trauma in eyes or non-paired fins of fifteen percent, or gas bubble trauma in eyes or non-paired fins of five percent and gas bubbles occlude more than twenty-five percent of the surface area of the fin or eyes. If gas bubble trauma exceeds these biological thresholds and spill is reduced, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be increased to the level specified in this order. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above 125 percent. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of 125 percent TDG levels in the tailrace of the dam.

    c. The tailrace maximum TDG criteria for spring spill in this modification will be applied in a manner consistent with the applicable requirements of the federal Endangered Species Act.

d. Physical monitoring must occur and be adequate for implementing the requirements of this order.

8. Voluntary fish passage spill during the summer spill season, occurring from June 16 through Aug. 31, is subject to the following conditions:

   a. Spill at a dam must be reduced when:

      i. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 120 percent of saturation; or

      ii. Instantaneous total dissolved gas levels exceed 125 percent of saturation in the tailrace of the dam, calculated as the average of the two highest hourly total dissolved gas measures in a calendar day.

   b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels if voluntary spill results in biological threshold exceedances when:

      i. More than 15 percent of salmonids examined show signs of gas bubble disease in their eyes or non-paired fins, or

      ii. More than five percent of salmonids examined show signs of gas bubble trauma in their eyes non-paired fins where more than 25 percent of the surface area is occluded by gas bubbles.

   c. Physical monitoring must occur and be adequate for implementing the requirements set out in this order.

9. The Corps must provide written notice to DEQ within 24 hours of any violations of the conditions in the modification as it relates to voluntary spill. Such notice must include actions proposed to reduce total dissolved gas levels or the reason(s) for no action.

10. No later than Jan. 31 following each year of this modification, the Corps must provide an annual written report to DEQ detailing the following:
    a. Flow and runoff descriptions for the spill season;
    b. Spill quantities and durations;
    c. Quantities of water spilled for fish versus spill for other reasons for each project;
    d. Data results from the physical and biological monitoring programs, including incidences of gas bubble trauma regardless of sample size;
    e. Evaluation of the relationship between observations of non-salmonid gas bubble trauma monitoring and exposure to elevated total dissolved gas levels;
    f. Description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels; and
    g. Implementation of gas abatement measures identified through adaptive management.

11. If requested, the Corps must report to the commission on any of the above matters or other matters relevant to this order.

12. The commission reserves the right to terminate or modify this order at any time.

For the purposes of Oregon's Order, ODEQ defines non-salmonid as including non-native species per their letter dated June 10, 2022 and email dated January 18, 2023. Gas bubble trauma monitoring in bi-state waters will include evaluation of non-native species in the population of non-salmonids to comply with Oregon's Order. WADOE's Rule Implementation Plan is unchanged and continues to require GBT evaluation of native non-salmonids.

The terminology that has been adopted to refer to the States' TDG Water Quality Standards (WQS) is the "gas cap." Gas cap spill is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state law. In its implementation of spill for fish passage, the Corps will operate its fish passage projects in 2025 to the spill levels identified in the CRSO EIS ROD, 2020 CRS BiOps, and Appendix B of the USG Commitments as extended and modified, and in accordance with the States' TDG standards described above, including applying the different state calculation methodologies. When the standards vary or conflict, the Corps will apply the more stringent standard.

2.2. Spill Caps

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing conditions to manage TDG within all applicable State standards. To accomplish this, the RCC determines "spill caps" for each of the Corps' lower Columbia and lower Snake River projects daily throughout the fish passage spill season. Spill caps are the maximum spill level at each project that is estimated to meet, but not exceed, the gas cap.

To calculate spill caps, the Corps evaluates observed and forecasted variables that influence TDG levels, including: (1) environmental conditions (e.g., total flow, wind, ambient temperature, barometric pressure, and incoming TDG from upstream); and (2) project operations (e.g., spill level, spill pattern, tailwater elevation, proportion of flow through the turbines, and project configuration).

During spill for fish passage, the Corps reviews spill caps daily and adjusts as necessary to define the maximum spill level that maintains TDG within applicable State standards. Additional information about how the Corps will manage TDG is described in the 2025 Water Management Plan (see Appendix 4: TDG Management Plan)[7].

Higher spill than the target spill levels identified in Tables 3, 4, and 5 may occur due to high river flow that exceeds powerhouse hydraulic capacity or due to a lack of power demand (load). During periods when spill is greater than the spill cap due to lack of load conditions, the Corps manages excess TDG on a system-wide basis by incrementally increasing spill at projects

[7] The Water Management Plan (WMP) and associated appendices are updated annually. *See* https://public.crohms.org/tmt/documents/wmp/.

throughout the system in the order of priority defined in the Spill Priority List[8]. For this purpose, the RCC also defines spill rates to target multiple TDG levels in project tailraces that exceed the gas cap. The order of priority is coordinated with regional sovereigns in the Technical Management Team (TMT) to allocate spill to projects to best manage system TDG while also considering how best to protect fish and other aquatic biota.

3. SPILLWAY OPERATIONS AND SPILL LEVEL PRECISION

The Corps plans to achieve the target spill levels defined in Tables 3, 4, and 5 to the extent feasible; however, actual hourly spill levels at each dam may vary depending on the precision of the spillbay gate settings, real-time fluctuations in flow and/or project head, or automatic load following**.** At each project, spill is distributed across the spillway according to patterns defined in the project-specific chapters of the FPP[9] to provide favorable fish passage conditions.

Spillbay gates are opened to the settings identified in the FPP spill pattern table that correspond to the spill level that is closest to the target but may be slightly higher or lower than the target spill level. Due to these physical limitations in spill level precision, the observed hourly average spill level may vary ±2 kcfs when the target spill is a flow rate (e.g., kcfs) and ±1% when the target spill is a percentage. Not all projects are able to achieve this level of precision (e.g., Little Goose and Bonneville dams). Additional flexibility for balancing reserves (±5%) could occur at John Day Dam (spring and summer) and The Dalles Dam (summer) as identified in Appendix B of the USG Commitments. More information regarding project-specific spill precision limitations may be found in Section 9 below.

Snake River projects make spillbay gate setting changes as soon as feasible in response to target spill changes; however, there may be instances when spill level changes are delayed by up to 1 hour or more due to operation of the navigation locks.

4. MODIFICATIONS TO PLANNED OPERATIONS AND IN-SEASON MANAGEMENT

For planning purposes, the operations described in the 2025 FOP assume average runoff conditions. Actual runoff varies in magnitude and timing and observed river flow may be higher or lower than average at any time such that modifications to the planned operations may be required. To accommodate these varying runoff conditions and other routinely observed conditions as they arise, the Corps, in conjunction with the other Action Agencies, NMFS, and USFWS, coordinates with regional sovereigns on these conditions and other planned operations through the review of the 2025 FOP prior to spring spill operations (see section 4.1). The Corps responds in real-time to these routine conditions and planned operations by implementing adjustments as conditions require without additional coordination.

For unanticipated and unplanned conditions that are not pre-coordinated, the Corps responds as necessary to adjust to the condition, and when possible, will use the existing regional

[8] Spill Priority List: https://public.crohms.org/tmt/documents/spill-priority/
[9] The FPP is coordinated annually with regional sovereigns through the FPOM. *See* https://public.crohms.org/tmt/documents/fpp/.

coordination process[10] to adaptively manage and make necessary in-season adjustments in spill and other fish operations (e.g., spill levels, spill caps, spill patterns, juvenile fish transportation, and pool operating ranges).

4.1. Conditions that May Require Adjustments to Planned Operations

Under certain conditions or circumstances, the Corps may be required to adjust spill higher or lower than the target spill level at one or more projects.

Planned and Routine Operational Adjustments:[11]

1. High flow conditions that exceed powerhouse hydraulic capacity and require spilling more than the target spill level.
2. Low flow conditions that require adjustments in spill level while maintaining project minimum generation requirements (see section 4.3.1. below).
3. Lack of power demand (load) resulting in increased spill.
4. Operational limitations, for example physical limitations of gate settings, spill patterns (see section 3), forebay elevation, and deadband[12].
5. Scheduled turbine unit and/or transmission outages that reduce powerhouse hydraulic capacity and require spilling more than the target spill level.* (see footnote 11)
6. Standard operations for transmission reliability (see section 4.4.1. below).*(see footnote 11)
7. Navigation safety concerns (see section 4.6. below).* (see footnote 11)
8. Transition periods between gas cap spill and lower spill rates (e.g., during performance standard spill blocks[13]) may result in actual hourly spill levels that are slightly higher or lower than targeted spill levels.

Non-routine or Unplanned Operational Adjustments:[14]

1. Contingency operations for transmission reliability (see section 4.4.2 below).

---

[10] In-season adaptive management changes in spill levels could include adjustments that address unintended biological consequences caused by spill (e.g., adult passage delays), for the juvenile fish transportation program, for research activities for studies to evaluate fish passage facilities, survival, or other fish-related issues. Spill patterns and biological testing protocols that have not been coordinated to-date will be considered through the regional coordination process using Regional Forum subcommittees, which include the TMT, Studies Review Workgroup (SRWG), Fish Facility Design Review Work Group (FFDRWG), and FPOM.

[11] Planned and Routine Operational Adjustments are spill adjustments due to (1) conditions that occur routinely every year (e.g., high or low flow), or (2) planned operations (e.g., scheduled maintenance, transit of fish transport barge in the tailrace). These are considered pre-coordinated through regional sovereign review of the FOP and the FPP and are implemented by the Action Agencies as conditions require and without additional coordination through the regional forum processes. Spill adjustments due to routine or planned operations are included in the monthly FOP Implementation Report in the hourly spill and flow charts (plots), and conditions with an (*) are reported in the "Pre-Coordinated Operations" Table. The FPP (Appendix A) identifies actions with pre-coordinated dates.

[12] Deadbands occur when turbine outflow cannot achieve some flow ranges. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows.

[13] "Performance standard" spill is a NMFS term and refers to spill levels intended to meet NMFS' performance standard testing, as described in the 2008 Biological Opinion and accompanying administrative record.

[14] Spill adjustments that occur due to non-routine or unplanned conditions or operations are implemented by the Action Agencies as conditions require and/or as coordinated with regional sovereigns through the in-season adaptive management process. Non-routine or Unplanned Operational Adjustments that affect spill levels are reported in the

2. Fish emergencies (e.g., high river temperatures that exceed levels safe for fish, adult fish passage blockages, actionable incidence rates of gas bubble trauma (GBT) incidence rates in either juvenile salmonids or non-salmonids[15], etc.).
3. Conditions related to project safety (e.g., erosion), health and human safety, navigation, or other unforeseen events that require spilling more or less than the target spill level.[16]
4. Other circumstances including human or programming error, unscheduled maintenance or outage, and other unanticipated events or emergencies.
5. In-season adjustments following adaptive management coordination through the existing regional coordination process (see section 4).

4.2. TMT Emergency Protocols

The Corps and the other Action Agencies operate the fourteen Columbia River System projects in emergency situations in accordance with the 2025 Emergency Protocols (WMP Appendix 1 – available online at https://public.crohms.org/tmt/documents/wmp/). This protocol identifies the process the Action Agencies, in coordination with NMFS and USFWS, use in the event of an emergency concerning project operations that impact planned fish protection measures. The emergency protocols also address the process for coordination with regional sovereigns.

4.3. Low Flow Operations

4.3.1. Minimum Generation

All lower Snake and lower Columbia River dams have a minimum generation requirement that has been established to support power system reliability (see section 4.4.). The Corps has identified minimum generation powerhouse outflow values derived from the lower limit of the ±1% peak efficiency operating range defined in the project-specific chapters of the FPP and from actual generation records (see Table 1). Values stated in Table 1 are approximate ranges that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

FOP Implementation Report Variance Table (and when warranted, a description may also be included in the Operational Adjustments section). When a Non-routine or Unplanned Operational Adjustment does not affect spill levels, information about this is provided in the Operational Adjustments section. If an adjustment continues into the next month, the adjustment is reported in the Pre-Coordinated Operations Table.

[15] *See* WAC 173-201A-200(1)(f)(ii)(B)(III), including WADOE's Rule Implementation Plan for Chapter 173-201A WAC Water Quality Standards for Surface Waters of the State of Washington (Publication 19-10-048; pages 7-9), and *Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5, including clarifications from Oregon Department of Environmental Quality email dated 18 January 2023, RE: Request for Clarification of Spring Non-Salmonid Monitoring Requirement.

[16] When a generator requires repair, ongoing operations may require modification to prepare a turbine unit for the necessary maintenance without further damaging infrastructure or jeopardizing personnel safety. To safely install taillogs in a unit adjacent to the spillway, it may be necessary to cease spill through some spillbays for up to 6 or more hours during the installation of the physical barriers to isolate the area and subsequently dewater the draft tube environment. An alternate spill pattern for use during the maintenance period using the remaining spillbays will be coordinated through FPOM.

1. Varying reservoir elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor deadband: the governor controls the number of megawatts the unit should generate but cannot precisely control a unit flow; variations may be 1-2% or more of unit flow. These variations can affect minimum generation ranges in Table 1.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase or decrease flow and generation within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only, not flow through individual turbine units.

All of the lower Snake River powerhouses may be required to keep one generating unit[17] online at all times for power system reliability under low river flow conditions, which may result in a reduction of spill at that project if there is insufficient flow in the river. Generally, units 1–3 are the priority units for operation during the fish passage season for adult fish attraction flow to the fish ladders, but unit priority is also based on availability. During low river flow conditions, the Corps operates the lower Snake River and lower Columbia River projects to the unit priority order specified in the FPP and minimum generation ranges identified in Table 1.

[17] Two generating units may be necessary at Ice Harbor Dam during elevated air temperatures to meet transmission requirements.

Table 1.— Minimum generation flow ranges (kcfs) for turbine units at Corps hydropower projects on the lower Snake and lower Columbia rivers.[18]

Project	Turbine Unit	Minimum Generation Flow Range[A] (kcfs)
Lower Granite	1, 3	11.6 – 12.7
	2[B]	17.8 – 18.8
	4, 5, 6	13.8 – 14.9
Little Goose	1, 2, 3	11.8 – 12.3
	4, 5, 6	14.3 – 14.9
Lower Monumental	1, 2, 3	11.7 – 12.9
	4, 6	13.8 – 14.6
	5[B]	17.8 – 19.0
Ice Harbor	1[C]	Out of service
	2	12.1 – 14.1
	3	8.6 – 10.3
	4[B]	12.2 – 13.5
	5, 6[B]	12.5 – 14.1
McNary	N/A	50 – 60 (may increase up to 80 for reserves)[D]
John Day	N/A	50 – 60 (may increase up to 80 for reserves)[D]
The Dalles	N/A	50 – 60
Bonneville	N/A	30 – 40 (may increase to 60 for reserves)[D]

A. "Minimum Generation" is the minimum number of megawatts (MW) that must be generated at each project to support power system reliability. This table defines the resulting flow range (kcfs) through turbines, which is a function of power output (MW), turbine efficiency, and project head.
B. Lower Granite Unit 2, Lower Monumental Unit 5, and Ice Harbor units 4, 5, and 6 are restricted due to fixed-blade (non-adjustable) runners that are set at a fixed angle (non-adjustable). If a unit is restored to an adjustable-blade Kaplan in-season, the minimum generation range will revert to the lower 1% limit.
C. Ice Harbor Unit 1 is being rebuilt with an adjustable-blade runner design that reduces impacts to fish, scheduled for completion in 2026. At that time, testing will be performed to confirm the operating range.
D. Powerhouse outflows may increase for reserves up to 80 kcfs at McNary Dam during spring and summer months, up to 80 kcfs at John Day Dam during spring months and up to 60 kcfs at Bonneville Dam during spring months (without triggering reporting requirements described in Section 4.1). Increased powerhouse generation allowances will allow for additional generation for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, the higher ranges will be utilized for reserves under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere (e.g., Grand Coulee and Chief Joseph dams to carry and deploy reserves) has been maximized. Powerhouse flows exceeding 80 kcfs at McNary and John Day dams or 60 kcfs at Bonneville Dam for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table. Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report (see section 10).

There may be situations when river flows are insufficient to maintain minimum generation in Table 1 and the target spill level identified in Tables 3, 4, and 5 every hour. Under these conditions, the lower Snake River projects operate one turbine unit at minimum generation and spill the remainder of outflow. The lower Columbia River projects also operate at minimum generation and pass the remaining outflow as spill down to minimum spill levels. Under low river flow conditions during spring spill operations, the Corps attempts to remain as close as

[18] The table is accurate as of March 2025 but may change in-season as coordinated through FPOM (see the FPP).

possible to spill target levels for either gas cap spill or other spill percentages or volumes, depending on which operation is targeted for a given hour. The inability to meet the target gas cap spill level due to low river flow does not preclude the ability of the Corps to target performance standard spill levels as specified in Table 4. Additionally, inflow provided by non-Federal projects upstream is often variable and uncertain, and in combination with low flow conditions, may result in instances where forebay elevations go outside of the restricted operating ranges for Snake River and Columbia projects described in Section 4.6.[19]

4.3.2. Navigation Lock Operation During Low Flows

At projects that have a target spill level that is a percentage of total outflow, emptying the navigation lock during low flow conditions may temporarily result in a reduced percentage of outflow that is reported as spill. During this time, the spill rate remains constant, but the spill reported as a percent of total outflow may be temporarily reduced below the target percentage. This occurs because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total project outflow than during periods of higher flow.

4.4. Operations for Transmission System Reliability

In managing the fish passage spill operations, the Corps and Bonneville plan to allocate generation and spill at the eight Corps projects on the lower Columbia and Snake rivers in accordance with the 2025 FOP. Periodically, to ensure the reliability of the transmission system when system conditions warrant, it is necessary to increase or decrease the amount of water flowing through a project's turbines and spillbays at one or more of these projects.

Consistent with past practice, if any of the transmission system conditions listed below are present and can be alleviated by temporarily modifying generation levels at one or more federal projects, the Action Agencies adjust generation and spill levels to avoid the transmission system impact. These events could result in actual spill being temporarily higher or lower than the target fish passage spill level. Such events may occur coincident with the transmission system event or in subsequent hour(s) should the event impact water balance at a specific hydro project or river reach. The Corps and Bonneville work to restore conditions to support target spill operations as soon as practicable. These actions are taken to minimize the risk and/or scope of a transmission system emergency and are reported in the monthly FOP Implementation Report (see section 10 below).

4.4.1. Standard Operations for Transmission Reliability

Consistent with past practice, the Action Agencies manage the fourteen Columbia River System projects to be prepared to provide electric reliability support as follows:

[19] Lower Snake River projects operate within the minimum operating pool (MOP) range during fish passage season (Table 2).

1. Ensuring sufficient range of generation capability is available to provide the Bonneville balancing authority[20] area with contingency reserves required by North American Electric Reliability Corporation (NERC) reliability standards.[21]
2. Ensuring generation is available to increase or decrease to balance load and generation within the Bonneville balancing authority area to support reliability.
3. Ensuring enough generating units are online and have sufficient capability to increase or decrease generation to meet the Bonneville balancing authority area frequency response obligations, consistent with reliability standard requirements.
4. Bonneville must first meet its reserve obligations for system reliability.[22] When conditions result in an inability to meet the target spill levels defined in Tables 4 and 5, Bonneville will make best efforts to minimize the allocation of reserves (decremental, DEC and/or incremental, INC) on fish passage projects if a spill reduction would be required to allocate the reserves.
5. Ensuring that there is generation operating at projects in specific locations sufficient for arming for Remedial Action Schemes (RAS).[23] RAS allow the transmission system to automatically respond to unplanned events on the power system by immediately dropping or reducing generation at those specified locations.
6. Maintaining minimum generation levels (see Table 1) at generators in specific locations to maintain correct voltage levels on the power system to ensure reliability.
7. Maintaining enough generation units online in diverse locations on the electrical grid to ensure system stability through rotating inertia.

4.4.2. Contingency Operations for Transmission Reliability

If the routine reliability tools described above are insufficient to resolve the transmission condition, the Action Agencies implement the preemptive actions detailed in the Power System Emergency Action Plan (Attachment 1 to the TMT Emergency Protocols referenced in section 4.2 above) if time permits. Where necessary, the fourteen Columbia River System projects will be called upon to relieve the following conditions:

1. Increasing or decreasing generation at projects (redispatch) in specific geographic locations to relieve heavily loaded transmission lines if required by system conditions. This includes adjusting generation that flows over specific transmission facilities to keep flows over those paths within the requirements of NERC reliability standards.
2. Increasing or decreasing generation to ensure transmission system stability and/or reliable load service in local areas under specific system conditions. For example, increasing

[20] A balancing authority is the responsible entity that maintains load-interchange-generation balance within a Balancing Authority Area and supports interconnection frequency in real time. Balancing authority area is the collection of generation, transmission, and loads within the metered boundaries of the designated balancing authority. The balancing authority maintains load-resource balance within this area.
[21] The Federal Energy Regulatory Commission has certified the NERC as the Electric Reliability Organization responsible for establishing and enforcing national reliability standards.
[22] For example, generators may be required to maintain generation levels above minimum generation to provide sufficient capability to reduce generation.
[23] Remedial Action Schemes are sets of automatic control circuits that switch various types of power system components on or off in response to disturbances on the interconnected transmission system.

generation at Ice Harbor Dam to support transmission stability, including providing load service to the Tri-Cities area of Washington, when system conditions require.
3. Responding to unanticipated significant events, including NERC Energy Emergency Alerts or other system emergencies, consistent with the Power System Emergency Action Plan included as Attachment 1 to the TMT Emergency Protocols.
4. Other unanticipated significant events (e.g., fires, earthquakes, etc.).

These actions are implemented consistent with the TMT Emergency Protocols (see section 4.2 above).

4.5. Turbine Unit Testing for Maintenance

Turbine units may be operationally tested prior to maintenance and prior to return to service by running the unit at speed no load, various loads within the ±1% of peak efficiency range, and, if necessary, up to full load, to allow for measurements and testing. Testing of a unit under maintenance is in addition to a unit operating at minimum generation required for power system reliability. Testing may deviate from unit operating priorities specified in FPP Chapters 2-9 and may use water that would otherwise be used for spill if the unit operating for reliability is at the bottom of the ±1% of peak efficiency range. Water is used from the powerhouse outflow allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps coordinates this testing with the region through FPOM. Unit outages for required maintenance are described in FPP Appendix A. Maintenance dates are subject to change.

4.6. Navigation Safety and Minimum Tailwater Elevations

Short-term adjustments in spill or minimum operating pool (MOP) elevations may be required at any of the fish passage projects to address navigation safety concerns.[24] This may include changes in spill patterns, reductions in spill, short-term spill curtailment, or operating above MOP. Adjustments to MOP may also be required to meet minimum tailwater elevations (Table 2). Current spill operations for fish passage result in complex downstream hydraulics that cause large fluctuations in tailwater elevations. The 2020 BiOps describe MOP at the lower Snake River projects as a 1.5-foot range above the minimum forebay elevation (Table 2). To clearly communicate the implementation of this operation, the term "MOP" will refer to the 1.5-foot operating range above the minimum forebay elevation at the lower Snake River projects (i.e., "MOP" is a 1.5-foot operating range).

The Corps will operate Lower Granite Dam at MOP with a 1.5-foot forebay operating range and a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint") from April 3 until August 31, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.[25] Little Goose, Lower Monumental and Ice Harbor dams will operate at MOP with a 1.5-foot forebay operating range and a 1.0-foot range soft constraint to

[24] The Corps conducts annual surveys to assess sedimentation in the reservoirs and under certain conditions. To ensure safe navigation, there may be a need to operate the pools above the MOP range.
[25] The Corps conducts a bathymetric survey of the federal navigation channel annually to assure a 14-foot depth is maintained in the federal navigation channel. With the dredging completed in winter 2022/2023, Lower Granite will operate in the normal MOP range (733.0-734.5 feet) from April 3 until August 31 (and within a 1.0-foot soft constraint range to the extent possible).

the extent possible from April 3 until August 14, unless adjusted on occasion to meet authorized project purposes, primarily navigation, except as noted below.

Table 2.— Normal and minimum operating pool (MOP) elevation ranges and minimum tailwater elevations for lower Snake River projects. [A]

Project	Normal Operating Elevation Range (ft)[B]		MOP Elevation Range (ft)[C]		Project Tailwater (ft)
	Minimum	Maximum	Minimum	Maximum	Minimum
Lower Granite	733.0	738.0	733.0	734.5	633.0
Little Goose	633.0	638.0	633.0	634.5	537.0
Lower Monumental	537.0	540.0	537.0	538.5	437.0
Ice Harbor	437.0	440.0	437.0	438.5	337.0

A. Elevations provided in feet above mean sea level (NGVD29).
B. August 15 – April 2, except at Lower Granite (September 1-April 2).
C. April 3 – August 14, except at Lower Granite (April 3 – August 31). Projects will be operated within a 1.0-foot range to the extent possible (referred to operationally as a "soft constraint").

Potential in-season adjustments to MOP, if necessary, will be an expanded forebay operating range (Expanded MOP) or raised minimum forebay elevation (Raised MOP), as described below.

Expanded MOP: If the 1.5-foot MOP range is insufficient to maintain navigation safety, the range is expanded (e.g., to 2 feet). For instance, some flow conditions may require a 2-foot forebay operating range at Ice Harbor to provide safe conditions for barge traffic at the navigation lock exit. These adjustments may be necessary for both commercial traffic and fish transport barges. Using Ice Harbor as an example, this type of adjustment would be described as "2-foot expanded MOP (437.0-439.0 feet)". Additionally, large within day fluctuations between gas cap spill and spill percentages or prescribed volumes may cause operational challenges in meeting MOP and an expanded MOP may be necessary, especially when combined with restricted turbine units that are not able to operate in the full ±1 percent range.

Raised MOP: If the minimum forebay elevation is insufficient to maintain navigation safety or meet project minimum tailwater elevations, the 1.5-foot MOP range is raised as necessary. Adjustments in MOP operations have been necessary at the lower Snake River projects, typically during lower flow conditions. For instance, low flows in combination with fish passage spill operations may impact reservoir elevations and cause dips below project minimum tailwater elevations or inadequate navigation depths. Using Little Goose as an example, this type of adjustment would be described as "1.5-foot raised MOP (634.5-636.0 feet)".

Spill Adjustments: High spill levels may create unsafe hydraulic conditions for commercial, non-commercial, and fish transportation barges entering and exiting the tailrace and/or while moored at the fish transport loading facility. Under these conditions, spill may be reduced temporarily as necessary to maintain safe navigation conditions for commercial, non-commercial, or fish transportation barges, which may result in temporarily filling the pool above the MOP range, depending on river flow.

5. JUVENILE FISH TRANSPORTATION PROGRAM

The best available information will be considered in the Corps' implementation of the juvenile fish transportation program operations at the Snake River collector projects in 2025. Should regional sovereigns recommend adjustments in transportation start dates that differ from those stated herein, the Corps uses the existing regional adaptive management process to reconcile recommended operational adjustments.

The following describes the proposed transportation operations for the lower Snake River projects. Detailed descriptions of project and transport facility operations to implement the juvenile fish transportation program are contained in the FPP Appendix B.

5.1. Lower Snake River Dams – Transport Operation and Timing

Transportation will be initiated at Lower Granite, Little Goose and Lower Monumental dams on April 24 (collection starting on April 23) or as coordinated through the TMT and the RIOG but begin no later than May 1. Transport begins the following day after fish collection and collected juvenile fish will be transported from each facility on a daily or every-other-day basis (depending on the number of fish) throughout the migration season. Transportation of spring migrants ends on June 20. Truck transportation of summer migrants at Lower Granite and Little Goose resumes on August 1 with allowance for TMT adaptive management adjustments and continues through October 31. Transportation operations are carried out at each project in accordance with relevant FPP operating criteria. Transportation and spill operations may be adjusted due to research, conditions at fish collection facilities (e.g., overcrowding or temperature extremes), or through the adaptive management process with FPOM and/or TMT (e.g., to respond to expected environmental conditions, to respond to recent transport vs in-river research results, to better match juvenile outmigration, or to achieve/maintain spill targets).

5.2. Transport Research – Seasonal Effects of Transport

An ongoing annual study will be conducted again in 2025 to determine seasonal effects of transporting fish from the Snake River to optimize a transportation strategy. Fish will be collected for this study at Lower Granite starting on April 14, with marking beginning on April 15.

Depending on the number of fish available, fish will be collected 1-2 days each week with tagging occurring on the day following collection. A barge will leave on Thursday (17 April) morning with all fish collected during the previous 1-2 days (excluding fish tagged for in-river survival, which will be released into Lower Granite Dam tailrace). If necessary to achieve the proper loading density, additional fish will be collected on 16 April (but not tagged). By barging all fish (minus the in-river group) during 1 to 3 days of collection, barge densities are expected to be maintained similar to what would occur under normal transport operations at that time of year. This pattern will occur the week preceding general transportation and will be incorporated into general transportation once that operation begins. The desired transported sample size is 6,000 wild Chinook, 4,000-6,000 wild steelhead, and 4,000-6,000 hatchery steelhead weekly for approximately five to six weeks.

6. FALL/WINTER SURFACE SPILL OPERATIONS

Surface spill operations in March–April and September–November (referred to in Appendix B of the USG Commitments Document as "Fall/Winter Spill Operations") will occur during the dates and times defined below in Table 3. Surface spill will occur via the project's spillway weir (RSW, TSW, or ASW[26]), except at The Dalles and Bonneville dams which do not have a spillway weir and will instead operate non-spillway surface passage routes as defined in Table 3.

Table 3.– Fall/Winter Surface Spill Operations.[A]

Project	Dates	Hours	Notes
LWG, LGS, LMN, IHR, MCN	March 1 – March 20	4 hours/day in the morning, 7 days/week	LGS ASW in high crest (~7 kcfs). MCN TSW in spillbay 20.
	March 21 – April 2 (Snake projects) / April 9 (MCN)	24 hours/day, 7 days/week	
	September 1 – November 15	4 hours/day in the morning, 7 days/week	
JDA	March 21 – April 9	24 hours/day, 7 days/week	Opening the JDA TSW requires a crew and crane and must be done during daylight hours. On March 21, an equivalent spill rate (~10 kcfs) will occur via the non-TSW pattern from 0001 hours until the TSW in spillbay 19 is opened in the morning as early as possible.
TDA Sluiceway	March 1 – December 15	24 hours/day, 7 days/week	TDA sluiceway is a non-spillway surface passage route. See FPP Chapter 3 for operating criteria.
BON B2CC	March 1–8	0600-1000 daily	BON PH2 corner collector (B2CC) is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.
	March 9–25	0600-1000, 1600-2000 daily	
	March 26 – August 31	24 hours/day, 7 days/week	
BON Sluiceway	Year-round	24 hours/day, 7 days/week	BON PH1 sluiceway is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.

A. Spill may be temporarily reduced below the FOP target spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.

7. SPRING FISH PASSAGE SPILL OPERATIONS

Spring spill operations occur April 3–June 20 at the four lower Snake River projects, and April 10–June 15 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for spring 2025 at each project are defined in Table 4. If deleterious impacts of the proposed spill operations are observed in-season, existing adaptive management processes may be employed to address the

[26] Depending on their design, spillway weirs are referred to as either "Removable" (RSW–applies to LWG, LMN, IHR), "Adjustable" (ASW–applies to LGS), or "Top" (TSW–applies to MCN and JDA).

cause of the impacts. Spill may be temporarily reduced at any project to ensure navigation safety or transmission reliability. In order to operate consistently with state water quality standards, spill may also be reduced if observed GBT levels exceed those identified in state water quality standards (*See* WASH. ADMIN. CODE § 173-201A-200(l)(f)(ii)(B)(III) and *Order Approving a Modification to Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5).

Spill up to the 125% gas cap is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state laws. This includes a criterion for not exceeding 126% TDG for the average of the two greatest hourly values within a day.

Table 4.— Summary of 2025 spring target spill levels at lower Snake River (April 3 – June 20) and lower Columbia River (April 10 – June 15) projects.

PROJECT	SPRING SPILL DATES	SPRING SPILL OPERATION
Lower Granite [A, C]	April 3 - June 20	24 hours/day: 125% Gas Cap
Little Goose [B, C]	April 3 – June 20	125% Gas Cap 24 hours/day (until adult criteria met) *then* 16 hours/day: 125% Gas Cap; 8 hours/day: 30% of outflow (Performance Standard)
Lower Monumental [A]	April 3 - June 20	24 hours/day: 125% Gas Cap
Ice Harbor	April 3 – June 20	24 hours/day: 125% Gas Cap
McNary	April 10 – June 15	24 hours/day: 125% Gas Cap
John Day [D]	April 10 – June 15	Daytime hours: 40% of outflow; Nighttime hours: 125% Gas Cap
The Dalles [E]	April 10 – June 15	24 hours/day: 40% of outflow (Performance Standard)
Bonneville [F]	April 10 – June 15	24 hours/day: 125% Gas Cap

A. Lower Granite and Lower Monumental Adult Delay Criteria – See Section 7.1.
B. Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2025, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000.
C. During periods of high river flow that exceeds powerhouse hydraulic capacity, implementing 8 consecutive hours of spill as described in Footnotes A and B may result in storing additional inflow in the forebay above MOP. If it is necessary to pond water to achieve the 8-hour block of spill during high inflow, water stored above MOP should be drafted out over the remaining hours by increasing spill to pass inflow from 1200-1600 hours, then increasing spill as necessary from 1600-0400 to draft the pool back to MOP. If it is forecasted that the drafting spill will result in exceeding 130% TDG in the tailrace, all 16 hours will be used to return the pool to MOP. In lack of load conditions performance standard spill blocks will be prioritized at Little Goose, Lower Monumental, and Lower Granite dams, in that order.
D. John Day Dam – Daytime hours are defined in FPP Chapter 4, Table JDA-5. Daytime hourly spill target of 40% river flows with ±5% flexibility in river flow for balancing reserves, consistent with current target spill level calculations.

E. The Dalles Dam –TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.
F. Bonneville Dam – Spill for fish passage should not exceed 150 kcfs due to erosion concerns.

7.1. Adult Migration Delay Protocol for Spring Spill Operations at Lower Granite and Lower Monumental Dams

Lower Granite and/or Lower Monumental daytime spill levels will be decreased to 40% of project outflow for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) when adult delay or passage issues are observed at both/either of these projects. An adult delay or passage issue occurs when the following three criteria are met: (1) *fewer than* 50% of the single departure event per tag ID of PIT-tagged adult spring/summer Snake River Chinook detected at the downstream project (i.e., Ice Harbor or Little Goose dams) arrive at the upstream project (i.e., Lower Monumental or Lower Granite dams) within 3 days and this pattern persists for 4 consecutive days,[27] (2) a running 3-day minimum of 7 PIT-tagged adult spring/summer Snake River Chinook are detected at the downstream projects,[28] and (3) if the upstream dam's average outflow was below 160 kcfs each day of the delay. If all three criteria are met, the Corps will implement a 40% daytime spill operation (adult daytime spill operation) for 8 hours per day during daytime hours (targeted start time between 0400-0800 if feasible) on the next calendar day and continue for 3 consecutive days. Based on the availability of information on the three criteria, the adult 40% daytime spill operation may begin as early as day 5 and no later than day 6. Consistent with past operations to reduce spill at Little Goose Dam, if lack of load conditions preclude the implementation of 40% spill to begin between 0400-0800, reduced spill will occur as soon as practicable during morning hours and continue for up to 8 consecutive hours. If 8 hours of consecutive spill at 40% was not feasible, a second block will start as soon as load conditions allow, continue for at least two consecutive hours, and will conclude no later than 2000 (see Table 4, footnote B).

Assuming *greater than* 50% of the single departure event per tag ID of PIT-tagged adults arrive at the upstream project by day 3 then standard operations (125% TDG spill 24/7) would be reinstated the calendar day after information becomes available, as early as day 4 and no later than day 5. If greater than 50% of the daily cohort does NOT arrive at the upstream project by day 3 and project average flow was below 160 kcfs, adult daytime spill operations would continue an additional day and would be evaluated again the following day as previously described. This would continue until the adult delay or passage issue has been resolved and the standard operations can be reinstated as described in Table 4.

[27] The return to 125% TDG spill 24/7 will be triggered if 50% or more of the running 3-day cohort for the most recent day (e.g., day 3 of adult daytime spill) is detected at the upstream dam. The agencies will use Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool for this purpose.
[28] The agencies will use the current Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool ("Running 3-day DART tool") to determine if criteria one and two have been met. See top panel, in-season graphics of Cumulative Arrival Percent by Days in Route to Lower Granite or Lower Monumental dams. https://www.cbr.washington.edu/dart/query/pitadult_reachdist

The TMT may consider in-season deviations from these criteria if unforeseen factors are reasonably expected to cause substantial delay (e.g., lack of load conditions, priority turbine unit outages, etc.) and the Fish Passage Operations and Maintenance (FPOM) Coordination Team may consider refinements to these triggers following each spring spill season.

8. SUMMER FISH PASSAGE SPILL OPERATIONS

Summer spill operations occur June 21–August 31 at the four lower Snake River projects, and June 16–August 31 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for summer 2025 at each project are defined in Table 5. At the Snake River Projects spill may ranges up to ±1 kcfs during the summer spill operation from August 1 – August 31.

Table 5.– Summary of 2025 summer target spill levels at lower Snake River and lower Columbia River projects.

PROJECT	EARLY SUMMER SPILL[A] (June 21/16 – July 31) (24 hrs/day)	LATE SUMMER SPILL[A] (August 1 – August 31) (24 hrs/day)
Lower Granite [B]	18 kcfs	RSW flow (as river flow allows)
Little Goose [B, C]	30%	ASW flow or 7 kcfs
Lower Monumental [B, D]	17 kcfs	RSW flow or 8 kcfs
Ice Harbor [B, E]	30%	RSW flow or 9 kcfs
McNary [F]	57%	2 TSWs flow or 20 kcfs
John Day	35% [G]	2 TSWs flow [H] or 20 kcfs
The Dalles	40% [G]	30% [G]
Bonneville	95 kcfs	50 kcfs

A. Spill may be temporarily reduced below the FOP target summer spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.
B. Late summer spill August 1-August 31 will be through the spillway weir or a constant spill rate through conventional spillbays using the appropriate FPP spill pattern. The spillway weir spill rate is a function of forebay elevation (as pool elevation increases, more water is spilled over the weir), as defined in the FPP. The spillway weirs will be operated per FPP criteria and closed when low flow criteria are met. When the spillway weir is closed, the spill target will transition to a constant spill rate through conventional spillbays and will not vary with a fluctuating forebay elevation.
C. Flow corresponds to the Little Goose ASW high crest elevation as adjusted relative to the forebay operating range (see FPP Chapter 8, section 2.3.2.7).
D. Flow corresponds to a Lower Monumental forebay elevation of 538.5 feet, the mid-point of the forebay range from 537-540 feet.
E. Flow corresponds to an Ice Harbor forebay elevation of 438.5 feet, the mid-point of the forebay range from 437-440 feet.
F. From June 16-July 31, McNary will adjust spill once a day to 57% of the previous day's average project outflow. The intent is to reduce the frequency of spillgate changes while implementing a more uniform pattern to the extent it can be done safely (see FPP Chapter 5, section 2.2.1.1).
G. Hourly spill percentage target of river flow with ±5% flexibility of river flow for balancing reserves, consistent with current target spill level calculations.
H. John Day will also spill from bay 2 open 1 stop (approximately 1.6 kcfs) during daylight hours when spill is through the TSWs only to maintain attraction flow to the north adult ladder, per FPP Chapter 4 (JDA), section 2.2.3.

9. PROJECT-SPECIFIC OPERATIONS

The following sections describe 2025 spill operations for each project. The Corps implements established spill patterns for all projects as described in the FPP. Additional information regarding spill precision outside these dates may be found in Section 3 above.

9.1. Lower Granite Dam

9.1.1. Fall/Winter Surface Spill (Table 3). The Lower Granite RSW spill rate will increase with increasing forebay elevation, from approximately 5.6 kcfs at the bottom of the normal forebay operating range up to 11.4 kcfs at the top of the range (see FPP Chapter 9, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.1.2. Spring Spill (Table 4): 125% gas cap (see Section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (see Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow, 8 hours/day.

9.1.3. Summer Spill (Table 5):

- June 21–July 31: 18 kcfs, 24 hours/day.
- August 1–31: RSW spill, 24 hours/day.

9.1.4. Operational Considerations: During low flow when spill is less than 15 kcfs and the RSW is open, Lower Granite will transition to alternate spill patterns defined in FPP Table LWG-7-ALT if needed to maintain the tailwater elevation at no lower than 633 feet. The project will switch to these alternate patterns to avoid or minimize the need to raise the Little Goose forebay operating range to keep from dropping below the Lower Granite minimum tailwater elevation.

9.2. Little Goose Dam

9.2.1. Fall/Winter Surface Spill (Table 3). The Little Goose ASW will be adjusted relative to forebay up to once per day to maintain a “high crest” elevation and a minimum of 7 kcfs spill (see FPP Chapter 8, section 2.3.2.7).

- March 1–20: ASW high crest 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: ASW high crest 24 hours/day, 7 days/week.
- September 1 – November 15: ASW high crest 4 hours/day in the morning, 7 days/week.

9.2.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3 until adult criteria are met, then 125% gas cap, 16 hours/day, and 30% of outflow (performance standard) 8 hours/day, through June 20 (Table 3, footnote B).

9.2.3. Summer Spill (Table 5):

- June 21–July 31: 30% of outflow, 24 hours/day (except when adjusted to a constant spill level during low flows, as described in Operational Considerations below).
- August 1–31: ASW spill or approximately 7 kcfs, 24 hours/day.

9.2.4. Operational Considerations:

- When the ASW is closed and project outflow is less than or equal to 38 kcfs, actual hourly average spill levels at Little Goose may range up to ±4% according to the spill patterns in FPP Chapter 8 Table LGS-11.
- During low flow conditions at Little Goose, spill may exceed the target percentage if the ASW is in service, which restricts the project to a fixed minimum spill level (i.e., spill cannot be reduced below the spill rate through the ASW, which may result in spilling more than the target percentage at lower outflows).
- During the 30% spill operation when project outflows are ≤ 32 kcfs, the spill operation will transition from 30% to a constant spill rate of approximately 7-11 kcfs to help stabilize project outflow, meet Lower Monumental target spill levels, and maintain MOP elevation at Little Goose. The constant spill level will be based on the previous day's average total project outflow, as follows: 11 kcfs when total outflow is 28.0 to 32.0 kcfs, 9 kcfs when total outflow is 24.0 to 27.9 kcfs, and 7 kcfs when total outflow is ≤ 23.9 kcfs. Actual spill may range up to ±1 kcfs from the target spill level. Spill changes will be made by 0300 each day.

9.3. Lower Monumental Dam

9.3.1. Fall/Winter Surface Spill (Table 3). The Lower Monumental RSW spill rate will increase with increasing forebay elevation, from approximately 6.7 kcfs at the bottom of the forebay operating range up to 9.5 kcfs at the top of the range (see FPP Chapter 7, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.3.2. Spring Spill (Table 4): 125% gas cap (section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (Section 7.1), then 125% gas cap, 16 hours/day, and 40% of outflow 8 hours/day. Spring spill will occur using the uniform pattern, except during low

flows (spill below 30 kcfs) when the bulk pattern will be used to avoid small gate openings that could impact fish.

9.3.3. Summer Spill (Table 5):

- June 21–July 31: 17 kcfs (bulk pattern), 24 hours/day.
- August 1–31: RSW spill or approximately 8 kcfs, 24 hours/day.

9.3.4. Operational Considerations: Transit of the juvenile fish barge across the Lower Monumental tailrace, docking, and departure from the collection facility, may require a reduction in spill below the target spill level for safety concerns. The towboat captain may request spill be reduced or eliminated during transit. During juvenile fish barge loading operations, spill is typically reduced to 15 kcfs using the bulk pattern, but can be reduced further, if necessary, for safety reasons. Barge loading duration can be up to 3.5 hours. Reducing spill may cause the Lower Monumental pool to briefly operate outside of MOP elevations.[29]

9.4. Ice Harbor Dam

9.4.1. Fall/Winter Surface Spill (Table 3). The Ice Harbor RSW spill rate will increase with increasing forebay elevation, from approximately 7.1 kcfs at the bottom of the forebay operating range up to 10.4 kcfs at the top of the range (see FPP Chapter 6, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 7 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 4 hours/day in the morning, 7 days/week.

9.4.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3–June 20.

9.4.3. Summer Spill (Table 5):

- June 21–July 31: 30%, 24 hours/day.
- August 1–31: RSW spill or approximately 9 kcfs, 24 hours/day.

9.4.4. Operational Considerations:

- When the RSW is open, the minimum project spill level is fixed at approximately 7.1-8.7 kcfs, depending on forebay elevation (i.e., spill cannot be reduced below the fixed volume through the RSW). This operational limitation results in spilling more

[29] With spill levels in spring 2025 targeting the gas cap for at least 16 hours/day, reducing spill at Lower Monumental for long durations could pose problems for staying within MOP at Ice Harbor Dam, the next downstream project.

than 30% when total outflow drops below approximately 28 kcfs. Per FPP section 2.3.2.7, the RSW is closed when day average outflow is below 30 kcfs and forecasted to stay below 30 kcfs for at least 3 days. However, outflow may drop below 28 kcfs on an hourly basis while the RSW is still open, resulting in spill greater than 30% for those hours.

- Currently, all but one of the five available Ice Harbor turbines have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (also referred to as "fixed-blade" or "locked-blade" units). Only Unit 3 has adjustable blades. As a result, turbine outflow cannot achieve some flow ranges, referred to as deadbands. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows. Unit 1 is currently out of service until 2026 to install a new adjustable-blade runner design.

9.5. McNary Dam

9.5.1. Fall/Winter Surface Spill (Table 3). The McNary TSW spill rate will increase with increasing forebay elevation, from approximately 8 kcfs at the bottom of the normal forebay operating range up to 11 kcfs at the top of the range.

- March 1–20: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.
- March 21 – April 9: Spillbay 20 TSW 24 hours/day, 7 days/week.
- September 1 – November 15: Spillbay 20 TSW 4 hours/day in the morning, 7 days/week.

9.5.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 10–June 15.

9.5.3. Summer Spill (Table 5):

- June 16–July 31: 57% of the previous day's average outflow, 24 hours/day. Spill changes will be made by 0300 each day.
- August 1–31: Two TSWs spill or 20 kcfs, 24 hours/day.

9.5.4. Operational Considerations:

- Currently, McNary spillbays are restricted due to hoists and cranes that need replacement. As a result, McNary will implement modified spill patterns. For more information, see FPP Chapter 5 (MCN), section 2.2.
- Currently, McNary Dam turbine units 5 and 6 have runner blades that are locked at a set angle (non-adjustable). As a result, the units are restricted to a very narrow ±1% operating range of approximately 10-12 kcfs (see FPP Chapter 5 Table MCN-

6-A) and there may instances when the unit is unable to stay within this restricted range.

9.6. John Day Dam

9.6.1. Fall/Winter Surface Spill (Table 3).

- March 21 – April 9: Spillbay 19 TSW spill 24 hours/day, 7 days/week.

- Opening the TSWs at John Day Dam requires a crew and gantry crane and must be done during daylight hours as weather allows. On March 21, spill will occur at an equivalent rate (approximately 10 kcfs) with the non-TSW pattern in FPP Table JDA-9 from 0001 hours until the TSW is opened in the morning.

9.6.2. Spring Spill (Table 4): 40% of outflow daytime and 125% gas cap nighttime, April 10–June 15, with priority to maintain 40% spill 24 hours/day at The Dalles Dam as needed for TDG management. Daytime hours are defined in FPP Chapter 4, Table JDA-5. A crew will install the TSW in spillbay 18 on the first day of spring spill as early as possible during daylight hours (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

- Daytime 40% of outflow with ±5% flexibility of river flows for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP implementation report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP implementation report.

9.6.3. Summer Spill (Table 5):

- June 16–July 31: 35% of outflow, 24 hours/day with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flows for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.

- August 1–31: Two TSWs or 20 kcfs, 24 hours/day. A crew will close both TSWs on the last normal workday of summer spill, Thursday, August 28, 2025, as late in the day as possible. Spill will be maintained at an equivalent rate of 20 kcfs through midnight on August 31 using the spill patterns with no TSWs (see TSW operating criteria in FPP Chapter 4, section 2.3.2.4).

9.6.4 Operational Considerations:

- Currently, turbine units 2, 3, 8, 9, 10, 11, and 13 at John Day have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (see FPP Chapter 4 Table JDA-7-A). As a result, the turbines have a restricted operating

range of approximately 17-19 kcfs and may not be able to stay within the narrow 1% turbine band associated with it.

- See the WMP sections 6.11.1.4 and Tables 2 and 5 and Section 6.11.1.3 for discussion of springtime pool elevations to dissuade nesting of Caspian terns at Blalock Island. This operation is also described in the FPP Appendix A. This higher forebay operation will increase the flow rate over the TSWs and may change tailrace flow patterns.

9.7. The Dalles

9.7.1. Fall/Winter Surface Spill (Table 3): The ice & trash sluiceway (ITS) is a powerhouse (non-spillway) surface passage route and will operate March 1–December 15, 24 hours/day, pursuant to criteria in FPP Chapter 3.

9.7.2. Spring Spill (Table 4): 40% of outflow, 24 hours/day, April 10–June 15. Maintain 40% spill 24 hours/day at The Dalles Dam and reduce John Day Dam TDG spill cap as needed for TDG management.

9.7.3. Summer Spill (Table 5):

- June 16–July 31: 40% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances for reserves will be reported in the Variance Table in the monthly FOP Implementation Report.

- August 1–31: 30% of outflow, 24 hours/day, with ±5% flexibility for balancing reserves, consistent with current target spill level calculations. Deviations outside of ±5% of river flow for reserves within the Bonneville balancing authority area will be reported in the Pre-Coordinated Operations Table in the monthly FOP Implementation Report (see section 10). Any other exceedances will be reported in the Variance Table in the monthly FOP Implementation Report.

9.7.4. Operational Considerations:

- Spill bays 9[30], 10, 11, 13, 16, 18, 19, and 23 are operationally restricted due to wire rope, structural and concrete erosion concerns.

9.8. Bonneville Dam

9.8.1. Fall/Winter Surface Spill (Table 3). The PH1 ice & trash sluiceway (ITS) and PH2 corner collector (B2CC) are powerhouse (non-spillway) surface passage routes and will

[30] Spillbay 9 at The Dalles Dam cannot be used due to failure of the trunnion pin in 2009.

operate pursuant to criteria in FPP Chapter 2:

- March 1–8: B2CC daily 0600-1000 hours.
- March 9–25: B2CC daily 0600-1000 and 1600-2000 hours.
- March 26–August 31: B2CC 24 hours/day, 7 days/week (beginning at 0600 on March 26).
- Year-round: ITS 24 hours/day, 7 days/week. From December 15–end of February, the ITS may be closed for up to 6 hours/day for maintenance.

9.8.2. Spring Spill (Table 4): 125% gas cap up to a maximum of 150 kcfs for fish passage spill (see section 2.1), 24 hours/day, April 10–June 15.

9.8.3. Summer Spill (Table 5):

- June 16–July 31: 95 kcfs, 24 hours/day.
- August 1–31: 50 kcfs, 24 hours/day.

9.8.4. Operational Considerations:

- Maximum fish passage spill level is 150 kcfs. This constraint is based on physical model observations indicating an increased incidence of rock deposition into the spillway stilling basin at spill ≥ 150 kcfs, which has caused erosion to the structure in the past.
- Minimum spill level is 50 kcfs; however, as observed in past years, to provide acceptable juvenile fish egress conditions in the tailrace under extreme low flow conditions, lower spill levels may be considered and coordinated through the TMT and/or FPOM.
- Actual hourly average spill levels at Bonneville Dam may range up to ±3 kcfs according to spill pattern tables in FPP Chapter 2.

10. FOP IMPLEMENTATION REPORTING

The Corps posts monthly FOP Implementation Reports between April and August on the following website: https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/. The updates include monthly project plots containing the following information:

- total flow: the total hourly river flow rate;
- generation flow: the hourly flow through the powerhouse turbine units;
- target spill: the spill target for that hour (Tables 3, 4 and 5);
- adjusted spill: the hourly spill level that can be achieved taking into consideration that spill may vary as a function of total river flow, forebay elevation, and generator capacity, and is

subject to routine operational adjustments that limit the ability to spill to the target spill (see section 4.1);
- actual spill: the hourly flow over the spillway; and,
- resultant 12-hour average TDG for the tailwater at each project.

The reports also provide information on non-routine or unplanned operational adjustments that arise during the spill program and address any spill adjustments due to emergency situations (such as unplanned maintenance or outages), and for contingency operations for transmission reliability. See section 4.1 for more information.

The Corps provides the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Hourly flow, generation flow, and spill quantity data for the lower Snake and Columbia River dams are posted to the following website:
    - https://public.crohms.org/report/projdata.htm (web reports with the most recent 8 days of hourly project data and the current month of daily project data).
    - https://public.crohms.org/tmt/wq/historical/ (links to historic hourly project data files in .csv format organized by month back to 2004 including temperature and TDG information).
- Water quality data are received via satellite from TDG Fixed Monitoring Sites (FMS) in the Columbia and Snake rivers every hour and placed on a Corps public website upon receipt. Hourly TDG and water temperature data are posted to the following websites:
    - https://public.crohms.org/report/total.html (web reports with hourly TDG, project outflow and spill for the previous 3 days).
    - https://public.crohms.org/ftppub/water_quality/tdg/ (links to historic hourly water quality data files for each FMS including barometric and total gas pressure, TDG and project outflow and spill in csv-format organized by month back to 2005).
    - Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps calculates both the highest 12-hour average TDG levels (Oregon and Washington spring method) and the highest consecutive 12-hour average TDG levels (Washington summer method) daily. These averages are reported at: https://public.crohms.org/ftppub/water_quality/12hr/.
- Spill cap information is posted to the following site each day: https://public.crohms.org/tmt/documents/ops/spill/caps/.

In addition to the monthly FOP Implementation Reports, the Corps provides status updates at the regularly scheduled TMT meetings about the 2025 fish passage spill operations, including reasonably detailed information that is relevant to the Corps' process for implementing fish passage spill.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-152:
2026 Fish Operations Plan

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, NORTHWESTERN DIVISION
PO BOX 2870
PORTLAND OR 97208-2870

2026 Fish Operations Plan

1. INTRODUCTION

The 2026 Fish Operations Plan (2026 FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish[1] passage at its four lower Snake River and four lower Columbia River dams and includes surface spill operations (March through early April), spring and summer spill operations (early April through August), and fall surface spill operations (September through mid-November). The 2026 FOP is responsive to the U.S. District Court for the District of Oregon's (District Court) Preliminary Injunction Order issued February 25, 2026 and amended on March 2, 2026. The Corps will implement the 2026 FOP consistent with that order. It is also consistent with spill operations for fish passage and the regional forum process for adaptive management and in-season management provisions outlined in the Record of Decision for the Columbia River System Operations Environmental Impact Statement (CRSO EIS ROD) dated September 28, 2020, CRSO Final EIS, 2020 National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS) Columbia River System (CRS) Biological Opinions (2020 CRS BiOps)[2], the Corps' requirements under the Endangered Species Act (ESA), and the ongoing consultation and communications with the relevant wildlife agencies to ensure consistency with the ESA. Other project operations and water management actions not specifically addressed in this document will be consistent with other guiding operative documents, including the 2026 Water Management Plan (WMP), seasonal WMP updates, and the 2026 Fish Passage Plan (FPP).

In addition to discussing project-specific fish passage spill operations, the 2026 FOP identifies factors that the Corps, the Bureau of Reclamation (Reclamation), and the Bonneville Power Administration (Bonneville) (collectively referred to as the "Action Agencies") must address in the context of operating this complex system of fourteen multiple purpose projects. The 2026 FOP includes a discussion of how the Corps manages fish passage spill and total dissolved gas (TDG), identifies Planned and Routine Operational Adjustments (Section 4) that influence fish passage spill, addresses adaptive management and in-season management processes for fish passage spill and other fish operations including the juvenile fish transportation program, and describes the Corps' monthly implementation reports.

[1] ESA-listed salmon and steelhead.
[2] The Corps, in coordination with the other Action Agencies, and NMFS, employs the Regional Implementation Oversight Group (RIOG) and technical teams including the Technical Management Team (TMT) and Fish Passage Operations & Maintenance (FPOM) coordination group, to coordinate with state, tribal and other federal experts for recommendations for implementing operations consistent with the 2020 BiOps.

2. MANAGEMENT OF SPILL FOR FISH PASSAGE AND TDG

2.1. State Water Quality Standards for TDG

The Corps will manage spill for fish passage in 2026 consistent with the State of Washington and the State of Oregon total dissolved gas (TDG) water quality standards (WQS).[3,4] The State of Washington, Department of Ecology (WADOE) adopted a WQS rule change which became effective in 2020 allowing spring juvenile fish passage spill operations to generate specified TDG levels in project tailraces (up to 125% TDG 12 hours, 126% TDG 2 hours), so long as the specified conditions are met, including that spring juvenile fish passage spill operations do not exceed the spill levels and durations reviewed in applicable ESA consultation documents. The Environmental Protection Agency (EPA) subsequently approved the rule change and found that the ESA consultation documents ensure that any spring spill regime using the revised criteria must be performed in accordance with the spill levels and durations evaluated in ESA consultation documents for effects to ESA-listed species of all life stages, including juvenile out-migrating salmonids, resident salmonids, and adult migrating salmonids. EPA's approval of the rule further states that "compliance with the ESA consultation documents is a condition precedent for the revised criteria and so the criteria are not applicable for the purposes of the [Clean Water Act (CWA)] (i.e., have no effect for CWA purposes) without the ESA consultation documents addressing spill operations that result in TDG saturation levels above the pre-existing criterion." *Letter to WADOE from EPA Re: The EPA's Action on Revisions to the [WADOE's] Surface Water Quality Standards for the Site-Specific Total Dissolved Gas Criteria in the Columbia and Snake Rivers, and Other Water Quality Standards Revisions* dated March 5, 2020, page 9.

The State of Oregon, through its Environmental Quality Commission, approved a modification to its TDG WQS of up to 125% TDG from April 1-June 15 and up to 120% TDG from June 16-August 31, so long as spring spill is "applied in a manner consistent with the applicable requirements of the federal [ESA]." (*Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem* dated December 31, 2024, page 4). Regarding Oregon's 105% TDG criterion, Oregon Department of Environmental Quality (ODEQ) clarified that this criterion does not apply to the Columbia River per their letter dated January 29, 2024. Both states have thus accommodated levels of TDG above 110% for fish passage spill operations for ESA-listed juvenile salmonids at Corps projects on the lower Snake and lower Columbia rivers, as follows:

---

[3] WASH. ADMIN. CODE § 173-201A-200(l)(f)) provides the maximum TDG criteria for each of the aquatic life use categories and displays Table 200 (I)(f) that states: "Total dissolved gas shall not exceed 110 percent of saturation at any point of sample collection." The code also addresses exceptions and adjustments, including a provision allowing for an adjustment of the TDG criteria to aid fish passage over hydroelectric dams. *See* https://apps.leg.wa.gov/WAC/default.aspx?cite=173-201A-200.

[4] OR. ADMIN. R. 340-041-0031 provides in part: "the concentration of TDG relative to atmospheric pressure at the point of sample collection may not exceed 110 percent of saturation." OR. ADMIN. R. 340-041-104(3) identifies findings the Environmental Quality Commission must make for the purpose of allowing increased spill for salmon migration. *See* https://www.oregon.gov/deq/wq/Documents/columbiaUSACEtmdlorder.pdf

Washington Administrative Code[5]:

WAC 173-201A-200(1)(f)(ii) and WAC 173-201A-200(1)(f)(ii)(A)

(ii) The TDG criteria may be adjusted to aid fish passage over hydroelectric dams that spill for anadromous juvenile fish as of the 2020 spill season. The elevated TDG levels are intended to allow increased fish passage without causing more harm to fish populations than caused by turbine fish passage. The following special fish passage exemptions for the Snake and Columbia Rivers apply when spilling water at dams is necessary to aid fish passage:

(A) TDG must not exceed:

• An average of 115 percent as measured in the forebays of the next downstream dams and must not exceed an average of 120 percent as measured in the tailraces of each dam (these averages are calculated as an average of the 12 highest hourly readings in a calendar day, relative to atmospheric pressure); and
• A maximum TDG saturation level of 125 percent calculated as an average of the two highest hourly TDG measures in a calendar day during spillage for fish passage.

WAC 173-201A-200(1)(f)(ii)(B)

(B) To further aid fish passage during the spring spill season (generally from April through June), spill may be increased up to the following levels as measured at the tailrace fixed site monitoring location:

• A maximum TDG saturation level of 125 percent calculated as an average of the 12 highest hourly TDG measures in a calendar day: and
• A maximum TDG saturation level of 126 percent calculated as an average of any two-consecutive hourly TDG measures. These TDG criteria may be applied in place of (f)(ii)(A) of this subsection during spring spill operations when applied in accordance with the following conditions:

(I) In addition to complying with the requirements of this chapter, the tailrace maximum TDG criteria at hydropower dams shall be applied in accordance with Endangered Species Act consultation documents associated with spill operations on the Snake and Columbia rivers, including operations for fish passage. The Endangered Species Act consultation documents are those by which dams may legally operate during the time that the adjusted criteria in (f)(ii)(B) of this subsection are in use.

(II) Application of the tailrace maximum TDG criteria must be accompanied by a department approved biological monitoring plan designed to measure impacts of fish exposed to increased TDG conditions throughout the spring spill season. Beginning in

[5] The text of the code is copied verbatim below for reference.

the year 2021, plans must include monitoring for non-salmonid fish species and must continue for a minimum of five years, and thereafter as determined by the department.

(III) TDG must be reduced to allowances specified in (f)(ii)(A) of this subsection if the calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of 50 fish required weekly) or non-salmonids (with a minimum sample size of 50 fish required weekly) exceeds:

- Gas bubble trauma in non-paired fins of 15 percent; or
- Gas bubble trauma in non-paired fins of five percent and gas bubbles occlude more than 25 percent of the surface area of the fin.

In accordance with WADOE's Rule Implementation Plan, if gas bubble trauma exceeds these biological thresholds, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be adjusted to allowances specified in this subsection. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above the ability to meet (f)(ii)(B) of this subsection. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of (f)(ii)(B) of this subsection.

Oregon Water Quality Standard Modification:

The Environmental Quality Commission approved the following modification[6] to the statewide standard for total dissolved gas (OAR 340-41-0031(2)) of 110 percent for the lower Columbia River at McNary, John Day, The Dalles and Bonneville dams, as provided for in OAR 340-41-0104(3):

1. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 125 percent for the period from April 1 through June 15.

2. The total dissolved gas standard for the Columbia River as measured in the tailraces of McNary, John Day, The Dalles, and Bonneville dams is 120 percent for the period from June 16 through Aug. 31.

3. These limits do not apply when the stream flow exceeds the seven-day, ten-year frequency flood.

4. The modified total dissolved gas standards will apply for five years, beginning Jan. 1, 2025, through Dec. 31, 2029 (calendar years 2025, 2026, 2027, 2028, and 2029).

5. The DEQ Director may approve additional periods of application of this modification up to 120 percent total dissolved gas as calculated in 8.a)i., beyond the April 1 to Aug. 31 period, subject to subsections 8.a) to 8.c) for reasons including passing Spring Creek

[6] The text of the modification is copied verbatim below for reference.

Hatchery fish releases and other voluntary fish passage operations, maintenance activities, and biological or physical studies of spillway structures and prototype fish passage devices. The Corps must notify DEQ in writing at least one week prior to the spill describing the proposed action, including its purpose, and the location and dates of elevated total dissolved gas levels. Spill must be reduced to meet the 110 percent total dissolved gas criterion if requested by the DEQ Director.

6. Application of the tailrace maximum TDG criteria must be accompanied by a DEQ-approved biological monitoring plan designed to measure impacts to fish exposed to increased TDG conditions. Plans must include monitoring for non-salmonid fish species. Gas bubble trauma monitoring may be halted if there is a high mortality risk due to compounded effects of the evaluation procedure and adverse environmental factors such as high stream temperatures.

7. Voluntary fish passage spill during the spring spill season, occurring from April 1 through June 15, is subject to the following conditions:

    a. Spill at a dam must be reduced when:

        i. Instantaneous total dissolved gas levels exceed 127 percent of saturation, calculated as the average of any two consecutive hourly TDG measurements in the tailrace of the dam; or

        ii. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 125 percent.

    b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels to 120 percent as calculated in 8.a)i. when:

        i. The calculated incidence of gas bubble trauma in salmonids (with a minimum sample size of fifty fish required weekly) or non-salmonids (with a minimum sample size of fifty fish required weekly) exceeds gas bubble trauma in eyes or non-paired fins of fifteen percent, or gas bubble trauma in eyes or non-paired fins of five percent and gas bubbles occlude more than twenty-five percent of the surface area of the fin or eyes. If gas bubble trauma exceeds these biological thresholds and spill is reduced, additional monitoring must demonstrate the incidence of gas bubble trauma below biological thresholds before TDG can be increased to the level specified in this order. Gas bubble trauma monitoring data shall be excluded from comparison to biological thresholds when higher than normal river flow contributes to excess spill above 125 percent. This monitoring data exclusion shall apply for one full calendar day after reduced river flow allows attainment of 125 percent TDG levels in the tailrace of the dam.

    c. The tailrace maximum TDG criteria for spring spill in this modification will be applied in a manner consistent with the applicable requirements of the federal Endangered Species Act.

d. Physical monitoring must occur and be adequate for implementing the requirements of this order.

8. Voluntary fish passage spill during the summer spill season, occurring from June 16 through Aug. 31, is subject to the following conditions:

    a. Spill at a dam must be reduced when:

        i. The average of the twelve highest hourly TDG measurements in the tailrace of the dam in a calendar day exceeds 120 percent of saturation; or

        ii. Instantaneous total dissolved gas levels exceed 125 percent of saturation in the tailrace of the dam, calculated as the average of the two highest hourly total dissolved gas measures in a calendar day.

    b. The DEQ Director may halt the voluntary spill program or require reductions in voluntary spill to reduce TDG levels if voluntary spill results in biological threshold exceedances when:

        i. More than 15 percent of salmonids examined show signs of gas bubble disease in their eyes or non-paired fins, or

        ii. More than five percent of salmonids examined show signs of gas bubble trauma in their eyes non-paired fins where more than 25 percent of the surface area is occluded by gas bubbles.

    c. Physical monitoring must occur and be adequate for implementing the requirements set out in this order.

9. The Corps must provide written notice to DEQ within 24 hours of any violations of the conditions in the modification as it relates to voluntary spill. Such notice must include actions proposed to reduce total dissolved gas levels or the reason(s) for no action.

10. No later than Jan. 31 following each year of this modification, the Corps must provide an annual written report to DEQ detailing the following:
    a. Flow and runoff descriptions for the spill season;
    b. Spill quantities and durations;
    c. Quantities of water spilled for fish versus spill for other reasons for each project;
    d. Data results from the physical and biological monitoring programs, including incidences of gas bubble trauma regardless of sample size;
    e. Evaluation of the relationship between observations of non-salmonid gas bubble trauma monitoring and exposure to elevated total dissolved gas levels;
    f. Description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels; and
    g. Implementation of gas abatement measures identified through adaptive management.

11. If requested, the Corps must report to the commission on any of the above matters or other matters relevant to this order.

12. The commission reserves the right to terminate or modify this order at any time.

For the purposes of Oregon's Order, ODEQ defines non-salmonid as including non-native species per their letter dated June 10, 2022 and email dated January 18, 2023. Gas bubble trauma monitoring in bi-state waters will include evaluation of non-native species in the population of non-salmonids to comply with Oregon's Order.

The language in WAC 173-201A-200(1)(f)(ii)(B)(II) states that monitoring for native nonsalmonid fish species must continue for a minimum of five years. The Action Agencies have conducted monitoring for five years and will continue to implement unless WADOE determines otherwise prior to implementation of spill for fish passage at levels that necessitate monitoring.

In its implementation of spill for fish passage, the Corps will operate its fish passage projects in 2026 consistent with the CRSO EIS ROD, 2020 CRS BiOps, the Court's Preliminary Injunction Order as amended, and in accordance with the States' TDG standards described above, including applying the different state calculation methodologies. WADOE's Rule Implementation Plan is unchanged and continues to require GBT evaluation of native non-salmonids.

The terminology that has been adopted to refer to the States' TDG Water Quality Standards (WQS) is the "gas cap." Gas cap spill is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state law. When the standards vary or conflict, the Corps will apply the more stringent standard.

2.2. Spill Caps

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing conditions to manage TDG within all applicable State standards. To accomplish this, the RCC determines "spill caps" for each of the Corps' lower Columbia and lower Snake River projects daily throughout the fish passage spill season. Spill caps are the maximum spill level at each project that is estimated to meet, but not exceed, the gas cap.

To calculate spill caps, the Corps evaluates observed and forecasted variables that influence TDG levels, including: (1) environmental conditions (e.g., total flow, wind, ambient temperature, barometric pressure, and incoming TDG from upstream); and (2) project operations (e.g., spill level, spill pattern, tailwater elevation, proportion of flow through the turbines, and project configuration).

During spill for fish passage, the Corps reviews spill caps daily and adjusts as necessary to define the maximum spill level that maintains TDG within applicable State standards.

Additional information about how the Corps will manage TDG is described in the 2026 Water Management Plan (see Appendix 4: TDG Management Plan)[7].

Higher spill than the target spill levels identified in Tables 3, 4, and 5 may occur due to high river flow that exceeds powerhouse hydraulic capacity or due to a lack of power demand (load). During periods when spill is greater than the spill cap due to lack of load conditions, the Corps manages excess TDG on a system-wide basis by incrementally increasing spill at projects throughout the system in the order of priority defined in the Spill Priority List[8]. For this purpose, the RCC also defines spill rates to target multiple TDG levels in project tailraces that exceed the gas cap. The order of priority is coordinated with regional sovereigns in the Technical Management Team (TMT) to allocate spill to projects to best manage system TDG while also considering how best to protect fish and other aquatic biota.

3. SPILLWAY OPERATIONS AND SPILL LEVEL PRECISION

The Corps plans to achieve the target spill levels defined in Tables 3, 4, and 5 to the extent feasible; however, actual hourly spill levels at each dam may vary depending on the precision of the spillbay gate settings, real-time fluctuations in flow and/or project head, or automatic load following**.** At each project, spill is distributed across the spillway according to patterns defined in the project-specific chapters of the FPP[9] to provide favorable fish passage conditions.

Spillbay gates are opened to the settings identified in the FPP spill pattern table that corresponds to the spill level that is closest to the target but may be slightly higher or lower than the target spill level. Due to these physical limitations in spill level precision, the observed hourly average spill level may vary ±2 thousand cubic feet per second (kcfs) when the target spill is a flow rate (e.g., kcfs, including when projects are spilling a percent of total project outflow based on the previous day's average flow). Not all projects are able to achieve this level of precision (e.g., Little Goose and Bonneville dams). More information regarding project-specific spill precision limitations may be found in Section 9 below.

Snake River projects make spillbay gate setting changes as soon as feasible in response to target spill changes; however, there may be instances when spill level changes are delayed by up to 1 hour or more due to operation of the navigation locks.

4. MODIFICATIONS TO PLANNED OPERATIONS AND IN-SEASON MANAGEMENT

For planning purposes, the operations described in the 2026 FOP assume average runoff conditions. Actual runoff varies in magnitude and timing and observed river flow may be higher or lower than average at any time such that modifications to the planned operations may be required. To accommodate these varying runoff conditions and other routinely observed

---

[7] The Water Management Plan (WMP) and associated appendices are updated annually. *See* http://public.crohms.org/tmt/documents/wmp/.
[8] http://public.crohms.org/tmt/documents/spill-priority/
[9] The FPP is coordinated annually with regional sovereigns through the FPOM. *See* http://public.crohms.org/tmt/documents/fpp/.

conditions as they arise, the Corps, in conjunction with the other Action Agencies, NMFS, and USFWS, coordinates with regional sovereigns on these conditions and other planned operations through the review of the 2026 FOP prior to spring spill operations (see section 4.1). The Corps responds in real-time to these routine conditions and planned operations by implementing adjustments as conditions require without additional coordination.

For unanticipated and unplanned conditions that are not pre-coordinated, the Corps responds as necessary to adjust to the condition, and when possible, will use the existing regional coordination process[10] to adaptively manage and make necessary in-season adjustments in spill and other fish operations (e.g., spill levels, spill caps, spill patterns, juvenile fish transportation, and pool operating ranges).

4.1. Conditions that May Require Adjustments to Planned Operations

Under certain conditions or circumstances, the Corps may be required to adjust spill higher or lower than the target spill level at one or more projects.

Planned and Routine Operational Adjustments:[11]

1. High flow conditions that exceed powerhouse hydraulic capacity and require spilling more than the target spill level.
2. Low flow conditions that require adjustments in spill level while maintaining project minimum generation requirements (see section 4.3.1. below).
3. Lack of power demand (load) resulting in increased spill.
4. Operational limitations, for example physical limitations of gate settings, spill patterns (see section 3), forebay elevation, and deadband[12].
5. Scheduled turbine unit and/or transmission outages that reduce powerhouse hydraulic capacity and require spilling more than the target spill level.* (see footnote 111)
6. Standard operations for transmission reliability (see section 4.4.1. below).* (see footnote 111)
7. Navigation safety concerns (see section 4.6. below).* (see footnote 111)

[10] In-season adaptive management changes in spill levels could include adjustments that address unintended biological consequences caused by spill (e.g., adult passage delays), for the juvenile fish transportation program, for research activities for studies to evaluate fish passage facilities, survival, or other fish-related issues. Spill patterns and biological testing protocols that have not been coordinated to-date will be considered through the regional coordination process using Regional Forum subcommittees, which include the TMT, Studies Review Workgroup (SRWG), Fish Facility Design Review Work Group (FFDRWG), and FPOM.

[11] Planned and Routine Operational Adjustments are spill adjustments due to (1) conditions that occur routinely every year (e.g., high or low flow), or (2) planned operations (e.g., scheduled maintenance, transit of fish transport barge in the tailrace). These are considered pre-coordinated through regional sovereign review of the FOP and the FPP and are implemented by the Action Agencies as conditions require and without additional coordination through the regional forum processes. Spill adjustments due to routine or planned operations are included in the monthly FOP Implementation Report in the hourly spill and flow charts (plots), and conditions with an (*) are reported in the "Pre-Coordinated Operations" Table. The FPP (Appendix A) identifies actions with pre-coordinated dates.

[12] Deadbands occur when turbine outflow cannot achieve some flow ranges. When targeting spill as a percent of outflow, these deadbands will result in a spill percentage that is above or below the target percentage at certain outflows.

8. Transition periods between gas cap spill and lower spill rates (e.g., during performance standard spill blocks[13]) may result in actual hourly spill levels that are slightly higher or lower than targeted spill levels.

Non-routine or Unplanned Operational Adjustments:[14]

1. Contingency operations for transmission reliability (see section 4.4.2 below).
2. Fish emergencies (e.g., high river temperatures that exceed levels safe for fish, adult fish passage blockages, actionable incidence rates of gas bubble trauma (GBT) incidence rates in either juvenile salmonids or non-salmonids[15], etc.).
3. Conditions related to project safety (e.g., erosion), health and human safety, navigation, or other unforeseen events that require spilling more or less than the target spill level.[16]
4. Other circumstances including human or programming error, unscheduled maintenance or outage, and other unanticipated events or emergencies.
5. In-season adjustments following adaptive management coordination through the existing regional coordination process (see section 4).

4.2. TMT Emergency Protocols

The Corps and the other Action Agencies operate the fourteen Columbia River System projects in emergency situations in accordance with the 2026 WMP Emergency Protocols (WMP Appendix 1). These Protocols identify the process the Action Agencies, in coordination with NMFS and USFWS, use in the event of an emergency concerning project operations that impact planned fish protection measures. The Emergency Protocols also address the process for coordination with regional sovereigns.

The most recent version of the Emergency Protocols is located at:
https://public.crohms.org/tmt/documents/wmp/2026/

---

[13] "Performance standard" spill is a NMFS term and refers to spill levels intended to meet NMFS' performance standard testing, as described in the 2008 Biological Opinion and accompanying administrative record.

[14] Spill adjustments that occur due to non-routine or unplanned conditions or operations are implemented by the Action Agencies as conditions require and/or as coordinated with regional sovereigns through the in-season adaptive management process. Non-routine or Unplanned Operational Adjustments that affect spill levels are reported in the FOP Implementation Report Variance Table (and when warranted, a description may also be included in the Operational Adjustments section). When a Non-routine or Unplanned Operational Adjustment does not affect spill levels, information about this is provided in the Operational Adjustments section. If an adjustment continues into the next month, the adjustment is reported in the Pre-Coordinated Operations Table.

[15] *See* WAC 173-201A-200(1)(f)(ii)(B)(III), including WADOE's Rule Implementation Plan for Chapter 173-201A WAC Water Quality Standards for Surface Waters of the State of Washington (Publication 19-10-048; pages 7-9), and *Order Approving a Modification to the Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 5, including clarifications from Oregon Department of Environmental Quality email dated 18 January 2023, RE: Request for Clarification of Spring Non-Salmonid Monitoring Requirement.

[16] When a generator requires repair, ongoing operations may require modification to prepare a turbine unit for the necessary maintenance without further damaging infrastructure or jeopardizing personnel safety. To safely install taillogs in a unit adjacent to the spillway, it may be necessary to cease spill through some spillbays for up to 6 or more hours during the installation of the physical barriers to isolate the area and subsequently dewater the draft tube environment. An alternate spill pattern for use during the maintenance period using the remaining spillbays will be coordinated through FPOM.

4.3. Low Flow Operations

4.3.1. Minimum Generation

All lower Snake and lower Columbia River dams have a minimum generation requirement that has been established to support power system reliability (see section 4.4.). The Corps has identified minimum generation powerhouse outflow values derived from the lower limit of the ±1% peak efficiency operating range defined in the project-specific chapters of the FPP and from actual generation records (see Table 1). Values stated in Table 1 are approximate ranges that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

1. Varying reservoir elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor deadband: the governor controls the number of megawatts the unit should generate but cannot precisely control a unit flow; variations may be 1-2% or more of unit flow. These variations can affect minimum generation ranges in Table 1.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase or decrease flow and generation within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only, not flow through individual turbine units.

All lower Snake River powerhouses may be required to keep one generating unit[17] online at all times for power system reliability under low river flow conditions, which may result in a reduction of spill at that project if there is insufficient flow in the river. Generally, units 1–3 are the priority units for operation during the fish passage season for adult fish attraction flow to the fish ladders, but unit priority is also based on availability. During low river flow conditions, the Corps operates the lower Snake River and lower Columbia River projects to the unit priority order specified in the FPP and minimum generation ranges identified in Table 1.

[17] Two generating units may be necessary at Ice Harbor Dam during elevated air temperatures to meet transmission requirements.

Table 1.— Minimum generation flow ranges (kcfs) for turbine units at Corps hydropower projects on the lower Snake and lower Columbia rivers.[18]

Project	Turbine Unit	Minimum Generation Flow Range[A] (kcfs)
Lower Granite	1, 3	11.6 – 12.7
	2[B]	17.8 – 18.8
	4, 5, 6	13.8 – 14.9
Little Goose	1, 2, 3	11.8 – 12.3
	4, 5, 6	14.3 – 14.9
Lower Monumental	1, 2, 3	11.7 – 12.9
	4, 5, 6	13.8 – 14.6
Ice Harbor	1[C]	TBD
	2	12.1 – 14.1
	3	8.6 – 10.3
	4[B]	12.2 – 13.5
	5, 6[B]	12.5 – 14.1
McNary	N/A	50 – 60
John Day	N/A	50 – 60 (may increase up to 80 for reserves) [D]
The Dalles	N/A	50 – 60
Bonneville	N/A	30 – 40

A. "Minimum Generation" is the minimum number of megawatts (MW) that must be generated at each project to support power system reliability. This table defines the resulting flow range (kcfs) through turbines, which is a function of power output (MW), turbine efficiency, and project head.
B. Lower Granite Unit 2 and Ice Harbor units 4, 5, and 6 are restricted due to fixed-blade (non-adjustable) runners that are set at a fixed angle (non-adjustable). If a unit is restored to an adjustable-blade Kaplan in-season, the minimum generation range will revert to the lower 1% limit.
C. Ice Harbor Unit 1 is being rebuilt with an adjustable-blade runner design that reduces impacts to fish, scheduled for completion in 2026. At that time, testing will be performed to confirm the operating range.
D. Powerhouse outflows may increase for reserves up to 80 kcfs at John Day Dam during spring months (without triggering reporting requirements described in Section 4.1). Increased powerhouse generation allowances will allow for additional generation for the purpose of providing real-time operators greater access to reserve capacity prior to requiring variance tracking or declarations of power system emergency. As needed, the higher ranges will be utilized for reserves under low flow conditions (e.g., minimum generation and spill the rest) and when flexibility elsewhere (e.g., Grand Coulee and Chief Joseph dams to carry and deploy reserves) has been maximized. Powerhouse flows exceeding 80 kcfs at John Day Dam for reserves will be reported in the Pre-Coordinated Operations Table. Any other exceedances will be reported in the Variance Table in the monthly FOP Implementation Report (see section 10).

There may be situations when river flows are insufficient to maintain minimum generation in Table 1 and the target spill level identified in Tables 3, 4, and 5 every hour. Under these conditions, the lower Snake River projects operate one turbine unit at minimum generation and spill the remainder of outflow. The lower Columbia River projects also operate at minimum generation and pass the remaining outflow as spill down to minimum spill levels. Under low river flow conditions during spring spill operations, the Corps attempts to remain as close as possible to spill target levels for either gas cap spill or other spill percentages or volumes, depending on which operation is targeted for a given hour. The inability to meet the target gas

[18] The table is accurate as of April 2026 but may change in-season as coordinated through FPOM (see the FPP).

cap spill level due to low river flow does not preclude the ability of the Corps to target performance standard spill levels as specified in Table 4. Additionally, inflow provided by non-Federal projects upstream is often variable and uncertain, and in combination with low flow conditions, may result in instances where forebay elevations go outside of the restricted operating ranges for Snake River and Columbia projects described in Section 4.6.[19]

4.3.2. Navigation Lock Operation During Low Flows

At projects that have a target spill level that is a percentage of total outflow, emptying the navigation lock during low flow conditions may temporarily result in a reduced percentage of outflow that is reported as spill. During this time, the spill rate remains constant, but the spill reported as a percent of total outflow may be temporarily reduced below the target percentage. This occurs because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total project outflow than during periods of higher flow.

4.4. Operations for Transmission System Reliability

In managing the fish passage spill operations, the Corps and Bonneville plan to allocate generation and spill at the eight Corps projects on the lower Columbia and Snake rivers in accordance with the 2026 FOP. Periodically, to ensure the reliability of the transmission system when system conditions warrant, it is necessary to increase or decrease the amount of water flowing through a project's turbines and spillbays at one or more of these projects.

Consistent with past practice, if any of the transmission system conditions listed below are present and can be alleviated by temporarily modifying generation levels at one or more federal projects, the Action Agencies adjust generation and spill levels to avoid the transmission system impact. These events could result in actual spill being temporarily higher or lower than the target fish passage spill level. Such events may occur coincident with the transmission system event or in subsequent hour(s) should the event impact water balance at a specific hydro project or river reach. The Corps and Bonneville work to restore conditions to support target spill operations as soon as practicable. These actions are taken to minimize the risk and/or scope of a transmission system emergency and are reported in the monthly FOP Implementation Report (see section 10 below).

4.4.1. Standard Operations for Transmission Reliability

Consistent with past practice, the Action Agencies manage the fourteen Columbia River System projects to be prepared to provide electric reliability support as follows:

[19] Lower Snake River projects operate within the minimum operating pool (MOP) range during fish passage season (Table 2).

1. Ensuring sufficient range of generation capability is available to provide the Bonneville balancing authority[20] area with contingency reserves required by North American Electric Reliability Corporation (NERC) reliability standards.[21]
2. Ensuring generation is available to increase or decrease to balance load and generation to support reliability, including bidding such generation into applicable markets to more efficiently dispatch generation to support reliability.[22]
3. Ensuring enough generating units are online and have sufficient capability to increase or decrease generation to meet the Bonneville balancing authority area frequency response obligations, consistent with reliability standard requirements.
4. Bonneville must first meet its reserve obligations for system reliability.[23] When conditions result in an inability to meet the target spill levels defined in Tables 4 and 5, Bonneville will make best efforts to minimize the allocation of reserves (decremental, DEC and/or incremental, INC) on fish passage projects if a spill reduction would be required to allocate the reserves.
5. Ensuring that there is generation operating at projects in specific locations sufficient for arming for Remedial Action Schemes (RAS).[24] RAS allow the transmission system to automatically respond to unplanned events on the power system by immediately dropping or reducing generation at those specified locations.
6. Maintaining minimum generation levels (see Table 1) at generators in specific locations to maintain correct voltage levels on the power system to ensure reliability.
7. Maintaining enough generation units online in diverse locations on the electrical grid to ensure system stability through rotating inertia.

4.4.2. Contingency Operations for Transmission Reliability

If the routine reliability tools described above are insufficient to resolve the transmission condition, the Action Agencies implement the preemptive actions detailed in the Power System Emergency Action Plan (Attachment 1 to the TMT Emergency Protocols referenced in section 4.2 above) if time permits. Where necessary, the fourteen Columbia River System projects will be called upon to relieve the following conditions:

1. Increasing or decreasing generation at projects (redispatch) in specific geographic locations to relieve heavily loaded transmission lines if required by system conditions.

---

[20] A balancing authority is the responsible entity that maintains load-interchange-generation balance within a Balancing Authority Area and supports interconnection frequency in real time. Balancing authority area is the collection of generation, transmission, and loads within the metered boundaries of the designated balancing authority. The balancing authority maintains load-resource balance within this area.

[21] The Federal Energy Regulatory Commission has certified the NERC as the Electric Reliability Organization responsible for establishing and enforcing national reliability standards.

[22] BPA relies on regional energy markets to help support transmission reliability and meet operational objectives. This clarification ensures BPA can bid in reserves to maintain access to those markets for transmission reliability purposes.

[23] For example, generators may be required to maintain generation levels above minimum generation to provide sufficient capability to reduce generation.

[24] Remedial Action Schemes are sets of automatic control circuits that switch various types of power system components on or off in response to disturbances on the interconnected transmission system.

This includes adjusting generation that flows over specific transmission facilities to keep flows over those paths within the requirements of NERC reliability standards.
2. Increasing or decreasing generation to ensure transmission system stability and/or reliable load service in local areas under specific system conditions. For example, increasing generation at Ice Harbor Dam to support transmission stability, including providing load service to the Tri-Cities area of Washington, when system conditions require.
3. Responding to unanticipated significant events, including NERC Energy Emergency Alerts or other system emergencies, consistent with the Power System Emergency Action Plan included as Attachment 1 to the TMT Emergency Protocols.
4. Other unanticipated significant events (e.g., fires, earthquakes, etc.).

These actions are implemented consistent with the TMT Emergency Protocols (see section 4.2 above).

4.5. Turbine Unit Testing for Maintenance

Turbine units may be operationally tested prior to maintenance and prior to return to service by running the unit at speed no load, various loads within the ±1% of peak efficiency range, and, if necessary, up to full load, to allow for measurements and testing. Testing of a unit under maintenance is in addition to a unit operating at minimum generation required for power system reliability. Testing may deviate from unit operating priorities specified in FPP Chapters 2-9 and may use water that would otherwise be used for spill if the unit operating for reliability is at the bottom of the ±1% of peak efficiency range. Water is used from the powerhouse outflow allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps coordinates this testing with the region through FPOM. Unit outages for required maintenance are described in FPP Appendix A. Maintenance dates are subject to change.

4.6. Navigation Safety and Minimum Tailwater Elevations

Short-term adjustments in spill or minimum operating pool (MOP) elevations may be required at any of the fish passage projects to address navigation safety concerns.[25] This may include changes in spill patterns, reductions in spill, short-term spill curtailment, or operating above MOP. Adjustments to MOP may also be required to meet minimum tailwater elevations (Table 2). Current spill operations for fish passage result in complex downstream hydraulics that cause large fluctuations in tailwater elevations. The 2020 BiOps describe MOP at the lower Snake River projects as a 1.5-foot range above the minimum forebay elevation (Table 2). To clearly communicate the implementation of this operation, the term "MOP" will refer to the 1.5-foot operating range above the minimum forebay elevation at the lower Snake River projects (i.e., "MOP" is a 1.5-foot operating range).

[25] The Corps conducts annual surveys to assess sedimentation in the reservoirs and under certain conditions. To ensure safe navigation, there may be a need to operate the pools above the MOP range.

Table 2.– Normal and minimum operating pool (MOP) elevation ranges and minimum tailwater elevations for lower Snake River projects.[A]

Project	Normal Operating Elevation Range (ft)[B]		MOP Elevation Range (ft)[C]		Project Tailwater (ft)
	Minimum	Maximum	Minimum	Maximum	Minimum
Lower Granite	733.0	738.0	733.0	734.5	633.0
Little Goose	633.0	638.0	633.0	634.5	537.0
Lower Monumental	537.0	540.0	537.0	538.5	437.0
Ice Harbor	437.0	440.0	437.0	438.5	337.0

A. Elevations provided in feet above mean sea level (NGVD29).
B. August 15 – April 2, except at Lower Granite (September 1-April 2).
C. April 3 – August 14, except at Lower Granite (April 3 – August 31). Projects will be operated within a 1.5-foot range.

Potential in-season adjustments to MOP, if necessary, will be an expanded forebay operating range (Expanded MOP) or raised minimum forebay elevation (Raised MOP), as described below.

Expanded MOP: If the 1.5-foot MOP range is insufficient to maintain navigation safety, the range is expanded (e.g., to 2 feet). For instance, some flow conditions may require a 2-foot forebay operating range at Ice Harbor to provide safe conditions for barge traffic at the navigation lock exit. These adjustments may be necessary for both commercial traffic and fish transport barges. Using Ice Harbor as an example, this type of adjustment would be described as "2-foot expanded MOP (437.0-439.0 feet)". Additionally, large within day fluctuations between gas cap spill and spill percentages or prescribed volumes may cause operational challenges in meeting MOP and an expanded MOP may be necessary, especially when combined with restricted turbine units that are not able to operate in the full ±1 percent range.

Raised MOP: If the minimum forebay elevation is insufficient to maintain navigation safety or meet project minimum tailwater elevations, the 1.5-foot MOP range is raised as necessary. Adjustments in MOP operations have been necessary at the lower Snake River projects, typically during lower flow conditions. For instance, low flows in combination with fish passage spill operations may impact reservoir elevations and cause dips below project minimum tailwater elevations or inadequate navigation depths. Using Little Goose as an example, this type of adjustment would be described as "1.5-foot raised MOP (634.5-636.0 feet)".

Spill Adjustments: High spill levels may create unsafe hydraulic conditions for commercial, non-commercial, and fish transportation barges entering and exiting the tailrace and/or while moored at the fish transport loading facility. Under these conditions, spill may be reduced temporarily as necessary to maintain safe navigation conditions for commercial, non-commercial, or fish transportation barges, which may result in temporarily filling the pool above the MOP range, depending on river flow.

5. JUVENILE FISH TRANSPORTATION PROGRAM

The best available information will be considered in the Corps' implementation of the juvenile fish transportation program operations at the Snake River collector projects in 2026. Should regional sovereigns recommend adjustments in transportation start dates that differ from those stated herein, the Corps uses the existing regional adaptive management process to reconcile recommended operational adjustments.

The following describes the proposed transportation operations for the lower Snake River projects. Detailed descriptions of project and transport facility operations to implement the juvenile fish transportation program are contained in the FPP Appendix B.

5.1. Lower Snake River Dams – Transport Operation and Timing

Transportation will be initiated at Lower Granite and Little Goose dams on April 24 (collection starting on April 23) or as coordinated through the TMT and the RIOG but begin no later than May 1. Transport begins the following day after fish collection and collected juvenile fish will be transported from each facility on a daily or every-other-day basis (depending on the number of fish) throughout the migration season. Transportation of spring migrants ends on June 20. Truck transportation of summer migrants at Lower Granite and Little Goose resumes on August 1 with allowance for TMT adaptive management adjustments and continues through October 31. Transportation operations are carried out at each project in accordance with relevant FPP operating criteria. Transportation and spill operations may be adjusted due to research, conditions at fish collection facilities (e.g., overcrowding or temperature extremes), or through the adaptive management process with FPOM and/or TMT (e.g., to respond to expected environmental conditions, to respond to recent transport vs in-river research results, to better match juvenile outmigration, or to achieve/maintain spill targets).

5.2. Transport Research – Seasonal Effects of Transport

An ongoing annual study will be conducted again in 2026 to determine seasonal effects of transporting fish from the Snake River to optimize a transportation strategy. Fish will be collected for this study at Lower Granite starting on April 13, with marking beginning on April 14.

Depending on the number of fish available, fish will be collected 1-2 days each week with tagging occurring on the day following collection. A barge will leave on Thursday (16 April) morning with all fish collected during the previous 1-2 days (excluding fish tagged for in-river survival, which will be released into Lower Granite Dam tailrace). If necessary to achieve the proper loading density, additional fish will be collected on 15 April (but not tagged). By barging all fish (minus the in-river group) during 1 to 3 days of collection, barge densities are expected to be maintained similar to what would occur under normal transport operations at that time of year. This pattern will occur the week preceding general transportation and will be incorporated into general transportation once that operation begins. The desired transported sample size is 6,000 wild Chinook, 4,000-6,000 wild steelhead, and 4,000-6,000 hatchery steelhead weekly for approximately five to six weeks.

6. FALL/WINTER SURFACE SPILL OPERATIONS

Surface spill operations in March–April and September–November will occur during the dates and times defined below in Table 3. Surface spill will occur via the project's spillway weir (RSW, TSW, or ASW[26]), except at The Dalles and Bonneville dams which do not have a spillway weir and will instead operate non-spillway surface passage routes as defined in Table 3.

Table 3.– Fall/Winter Surface Spill Operations in 2026.[A]

Project	Dates	Hours	Notes
LWG, LGS, LMN, IHR, MCN	March 1 – March 20	4 hours/day in the morning, 3 days/week	LGS ASW in high crest (~7 kcfs). MCN TSW in spillbay 20 March 1-April 9 and in spillbays 19, 20 September 1-November 15.
	March 21 – April 2 (Snake projects) / April 9 (MCN) September 1 – November 15	24 hours/day, 7 days/week	
JDA [B]	March 21 – April 9 (TSW19) September 1 – November 15 (TSW18 and TSW19)	24 hours/day, 7 days/week	Opening the JDA TSW requires a crew and crane and must be done during daylight hours as weather allows. On March 21, the TSW in spillbay 19 will be opened in the morning as early as possible. On November 15, both TSWs will be closed as late as possible during daylight hours, then spill maintained at ~20 kcfs with non-TSW patterns through 2359 hours.
TDA Sluiceway	Year-round	24 hours/day, 7 days/week	TDA sluiceway is a non-spillway surface passage route. See FPP Chapter 3 for operating criteria.
BON B2CC	March 1–8	0600-1000 daily	BON PH2 corner collector (B2CC) is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.
	March 9–25	0600-1000, 1600-2000 daily	
	March 26 begin year-round	24 hours/day, 7 days/week	
BON Sluiceway	Year-round	24 hours/day, 7 days/week	BON PH1 sluiceway is a non-spillway surface passage route. See FPP Chapter 2 for operating criteria.

A. Spill may be temporarily reduced below the FOP target spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.
B. John Day Dam will also spill from bay 2 open 1 stop (approximately 1.6 kcfs) 24 hours/day September 1-November 15 to maintain attraction flow to the North Shore adult fish ladder, per FPP Chapter 4 (JDA).

[26] Depending on their design, spillway weirs are referred to as either "Removable" (RSW–applies to LWG, LMN, IHR), "Adjustable" (ASW–applies to LGS), or "Top" (TSW–applies to MCN and JDA).

7. SPRING FISH PASSAGE SPILL OPERATIONS

Spring spill operations occur April 3–June 20 at the four lower Snake River projects, and April 10–June 15 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for spring 2026 at each project are defined in Table 4. If deleterious impacts of the proposed spill operations are observed in-season, existing adaptive management processes may be employed to address the cause of the impacts. Spill may be temporarily reduced at any project to ensure navigation safety or transmission reliability. In order to operate consistently with state water quality standards, spill may also be reduced if observed GBT levels exceed those identified in state water quality standards (*See* WASH. ADMIN. CODE § 173-201A-200(l)(f)(ii)(B)(III) and *Order Approving a Modification to Oregon's Water Quality Standard for Total Dissolved Gas in the Columbia River Mainstem*, page 4-5).

Spill up to the 125% gas cap is spill to the maximum level that meets, but does not exceed, the TDG criteria allowed under state laws. This includes a criterion for not exceeding 126% TDG for the average of the two greatest hourly values within a day.

Table 4.— Summary of 2026 spring target spill levels at lower Snake River (April 3 – June 20) and lower Columbia River (April 10 – June 15) projects.

PROJECT	SPRING SPILL DATES	SPRING SPILL OPERATION
Lower Granite	April 3 - June 20	24 hours/day: 125% Gas Cap
Little Goose [A, B, C]	April 3 – June 20	125% Gas Cap 24 hours/day (until adult criteria met) *then* 16 hours/day: 125% Gas Cap; 8 hours/day: 30% of outflow (Performance Standard)
Lower Monumental [D]	April 3 - June 20	24 hours/day: 125% Gas Cap
Ice Harbor	April 3 – June 20	24 hours/day: 125% Gas Cap
McNary	April 10 – June 15	24 hours/day: 125% Gas Cap
John Day	April 10 – June 15	24 hours/day: 125% Gas Cap
The Dalles [C, E]	April 10 – June 15	24 hours/day: 40% of outflow (Performance Standard)
Bonneville [F]	April 10 – June 15	24 hours/day: 125% Gas Cap

A. Little Goose Adult Criteria –Within 1 business day of when the earliest of the following conditions occurs: (1) a cumulative total of 25 adult spring Chinook salmon (not including jacks) pass Lower Monumental Dam; or (2) a cumulative total of 50 adult spring Chinook salmon (not including jacks) pass Ice Harbor Dam; or (3) April 24, 2026, the Corps will implement performance standard spill at Little Goose Dam for 8 consecutive AM hours (April 3–15 starting at 0500 hours; April 16–June 20 starting at 0400 hours) to target hours of peak adult passage. If lack of load conditions preclude the implementation of performance standard spill during the targeted periods, performance standard spill will begin as soon as practicable during AM hours and continue for up to 8 consecutive hours. If a second block is needed, it will start as soon as load conditions allow, continue for at least two consecutive hours, and conclude no later than 2000.

B. During periods of high river flow that exceeds powerhouse hydraulic capacity, implementing 8 consecutive hours of spill as described in Footnote A may result in storing additional inflow in the forebay above MOP. If it is necessary to pond water to achieve the 8-hour block of spill during high inflow, water stored above MOP should be drafted out over the remaining hours by increasing spill to pass inflow from 1200-1600 hours, then increasing spill as necessary from 1600-0400 to draft the pool back to MOP. If it is forecasted that the drafting spill will result in

exceeding 130% TDG in the tailrace, all 16 hours will be used to return the pool to MOP. In lack of load conditions performance standard spill blocks will be prioritized at Little Goose, Lower Monumental dams, in that order.
C. All projects denoted by this footnote will adjust spill once a day to the indicated percentage level of the previous day's average project outflow. The intent is to reduce the frequency of spillgate changes.
D. Lower Monumental Adult Delay – See Section 7.1.
E. TDG in The Dalles tailrace may fluctuate up to 125% prior to reducing spill at upstream projects or reducing spill at The Dalles below 40%. Maintain 40% spill for 24 hours at The Dalles and reduce John Day spill below the 125% TDG spill cap as needed for TDG management. Spill above 40%, up to 125% TDG, may occur for TDG management or for carrying reserves.
F. Bonneville Dam – Spill for fish passage should not exceed 150 kcfs due to erosion concerns.

7.1. Adult Migration Delay Protocol for Spring Spill Operations at Lower Monumental Dam

At Lower Monumental Dam, monitor and manage adult conversion rates in-season via TMT process.[27]

8. SUMMER FISH PASSAGE SPILL OPERATIONS

Summer spill operations occur June 21–August 31 at the four lower Snake River projects, and June 16–August 31 at the four lower Columbia River projects. The Corps initiates spill at 0001 hours, or shortly after midnight, at each of the projects on the start date. Target spill levels for summer 2026 at each project are defined in Table 5. At the Snake River Projects spill may ranges up to ±1 kcfs during the summer spill operation from August 1 – August 31.

Table 5.– Summary of 2026 summer target spill levels at lower Snake River and lower Columbia River projects.

PROJECT	SUMMER SPILL[A] (June 21/16 – August 31) (24 hrs/day)
Lower Granite	18 kcfs
Little Goose [B]	30%
Lower Monumental	17 kcfs
Ice Harbor [B]	30%
McNary [B]	57%
John Day [B]	35%
The Dalles [B]	40%
Bonneville	95 kcfs

A. Spill may be temporarily reduced below the FOP target summer spill level at any project if necessary to ensure navigation safety or transmission reliability, or to avoid exceeding State TDG standards.
B. From June 16-August 31, all projects denoted by this footnote will adjust spill once a day to the indicated percentage level of the previous day's average project outflow. The intent is to reduce the frequency of spillgate changes.

[27] The agencies will use all available information including adult dam counts and the current Columbia River DART's Reach Distribution and Delay for PIT Tag Adult Returns tool ("Running 3-day DART tool") to monitor adult delay. See top panel, in-season graphics of Cumulative Arrival Percent by Days in Route to Lower Monumental Dam. https://www.cbr.washington.edu/dart/query/pitadult_reachdist

9. PROJECT-SPECIFIC OPERATIONS

The following sections describe 2026 spill operations for each project. The Corps implements established spill patterns for all projects as described in the FPP. Additional information regarding spill precision outside these dates may be found in Section 3 above.

9.1. Lower Granite Dam

9.1.1. Fall/Winter Surface Spill (Table 3). The Lower Granite RSW spill rate will increase with increasing forebay elevation, from approximately 5.6 kcfs at the bottom of the normal forebay operating range up to 11.4 kcfs at the top of the range (see FPP Chapter 9, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 3 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 24 hours/day, 7 days/week.

9.1.2. Spring Spill (Table 4): 125% gas cap (see Section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (see Section 7.1), then 125% gas cap, 16 hours/day, and 40% of previous day average outflow, 8 hours/day.

9.1.3. Summer Spill (Table 5):

- June 21–August 31: 18 kcfs, 24 hours/day.

9.2. Little Goose Dam

9.2.1. Fall/Winter Surface Spill (Table 3). The Little Goose ASW will be adjusted relative to forebay up to once per day to maintain a "high crest" elevation and a minimum of 7 kcfs spill (see FPP Chapter 8, section 2.3.2.7).

- March 1–20: ASW high crest 4 hours/day in the morning, 3 days/week.
- March 21 – April 2: ASW high crest 24 hours/day, 7 days/week.
- September 1 – November 15: ASW high crest 24 hours/day, 7 days/week.

9.2.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3 until adult criteria are met, then 125% gas cap, 16 hours/day, and 30% of previous day average outflow (performance standard) 8 hours/day, through June 20 (Table 3, footnote B).

9.2.3. Summer Spill (Table 5):

- June 21–August 31: 30% of previous day average outflow, 24 hours/day (except when adjusted to a constant spill level during low flows, as described in Operational Considerations below). Spill changes will be made by 0300 each day.

9.2.4. Operational Considerations:

9.3. Lower Monumental Dam

9.3.1. Fall/Winter Surface Spill (Table 3). The Lower Monumental RSW spill rate will increase with increasing forebay elevation, from approximately 6.7 kcfs at the bottom of the forebay operating range up to 9.5 kcfs at the top of the range (see FPP Chapter 7, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 3 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 24 hours/day, 7 days/week.

9.3.2. Spring Spill (Table 4): 125% gas cap (section 2.1), 24 hours/day, April 3–June 20. If adult passage delay is observed (Section 7.1), then 125% gas cap, 16 hours/day, and 40% of previous day average outflow 8 hours/day. Spring spill will occur using the uniform pattern, except during low flows (spill below 30 kcfs) when the bulk pattern will be used to avoid small gate openings that could impact fish.

9.3.3. Summer Spill (Table 5):

- June 21–August 31: 17 kcfs (bulk pattern), 24 hours/day.

9.4. Ice Harbor Dam

9.4.1. Fall/Winter Surface Spill (Table 3). The Ice Harbor RSW spill rate will increase with increasing forebay elevation, from approximately 7.1 kcfs at the bottom of the forebay operating range up to 10.4 kcfs at the top of the range (see FPP Chapter 6, section 2.3.2.6).

- March 1–20: RSW spill 4 hours/day in the morning, 3 days/week.
- March 21 – April 2: RSW spill 24 hours/day, 7 days/week.
- September 1 – November 15: RSW spill 24 hours/day, 7 days/week.

9.4.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 3–June 20.

9.4.3. Summer Spill (Table 5):

- June 21–August 31: 30% of previous day average outflow, 24 hours/day. Spill changes will be made by 0300 each day.

9.5. McNary Dam

9.5.1. Fall/Winter Surface Spill (Table 3). The McNary TSW spill rate will increase with increasing forebay elevation, from approximately 8 kcfs at the bottom of the normal

forebay operating range up to 11 kcfs at the top of the range.

- March 1–20: Spillbay 20 TSW 4 hours/day in the morning, 3 days/week.
- March 21 – April 9: Spillbay 20 TSW 24 hours/day, 7 days/week.
- September 1 – November 15: Spillbays 19 and 20 TSWs 24 hours/day, 7 days/week.

9.5.2. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 10–June 15.

9.5.3. Summer Spill (Table 5):

- June 16–August 31: 57% of previous day average outflow, 24 hours/day. Spill changes will be made by 0300 each day.

9.5.4. Operational Considerations:

- Currently, McNary spillbays are restricted due to hoists and cranes that need replacement. As a result, McNary will implement modified spill patterns. For more information, see FPP Chapter 5 (MCN), section 2.2.
- Currently, McNary Dam turbine units 5 and 6 have runner blades that are locked at a set angle (non-adjustable). As a result, the units are restricted to a very narrow ±1% operating range of approximately 10-12 kcfs (see FPP Chapter 5 Table MCN-6-A) and there may be instances when the unit is unable to stay within this restricted range.

9.6. John Day Dam

9.6.1. Fall/Winter Surface Spill (Table 3).

- March 21 – April 9: Spillbay 19 TSW 24 hours/day, 7 days/week.
- September 1 – November 15: Spillbays 18 and 19 TSWs 24 hours/day, 7 days/week.

9.6.2. Opening the TSWs at John Day Dam requires a crew and gantry crane and must be done during daylight hours as weather allows. On March 21, spill will occur as soon as feasible, when the TSW is opened in the morning. On November 15, both TSWs will be closed as late as possible during daylight hours, then spill maintained at approximately 20 kcfs via the non-TSW pattern until 2359 hours.

9.6.3. Spring Spill (Table 4): 125% gas cap (see section 2.1), 24 hours/day, April 10–June 15, with priority to maintain 40% spill 24 hours/day at The Dalles Dam as needed for TDG management. Daytime hours are defined in FPP Chapter 4, Table JDA-5.

9.6.4. Summer Spill (Table 5):

- June 16–August 31: 35% of previous day average outflow, 24 hours/day. Spill changes will be made by 0300 each day.

.9.6.4 Operational Considerations:

- Currently, turbine units 2, 3, 7, 8, 9, 10, 11, and 13 at John Day have runner blades that are locked at a set angle (non-adjustable) and a smaller operating range (see FPP Chapter 4 Table JDA-7-A). As a result, the turbines have a restricted operating range of approximately 17-19 kcfs and may not be able to stay within the narrow 1% turbine band associated with it.

- See the WMP sections 6.11.1.4 and Tables 2 and 5 and Section 6.11.1.3 for discussion of springtime pool elevations to dissuade nesting of Caspian terns at Blalock Island. This operation is also described in the FPP Appendix A. This higher forebay operation will increase the flow rate over the TSWs and may change tailrace flow patterns.

9.7. The Dalles

9.7.1. Fall/Winter Surface Spill (Table 3): The ice & trash sluiceway (ITS) is a powerhouse (non-spillway) surface passage route and will operate year-round, 24 hours/day, pursuant to criteria in FPP Chapter 3. Outages for maintenance will be coordinated with FPOM.

9.7.2. Spring Spill (Table 4): 40% of previous day average outflow, 24 hours/day, April 10–June 15. Spill changes will be made by 0300 each day. Maintain 40% of previous day average outflow spill 24 hours/day at The Dalles Dam and reduce John Day Dam TDG spill cap as needed for TDG management.

9.7.3. Summer Spill (Table 5):

- June 16–August 31: 40% of previous day average outflow, 24 hours/day. Spill changes will be made by 0300 each day.

9.7.4. Operational Considerations:

- Spill bays 9[28], 10, 11, 13, 16, 18, 19, and 23 are operationally restricted due to wire rope, structural and concrete erosion concerns.

9.8. Bonneville Dam

9.8.1. Fall/Winter Surface Spill (Table 3). The PH1 ice & trash sluiceway (ITS) and PH2 corner collector (B2CC) are powerhouse (non-spillway) surface passage routes and will

[28] Spillbay 9 at The Dalles Dam cannot be used due to failure of the trunnion pin in 2009.

operate pursuant to criteria in FPP Chapter 2:

- March 1–8: B2CC daily 0600-1000 hours.
- March 9–25: B2CC daily 0600-1000 and 1600-2000 hours.
- March 26: Begin year-round B2CC 24 hours/day, 7 days/week. Outages for maintenance will be coordinated with FPOM.
- Year-round: ITS 24 hours/day, 7 days/week. Outages for maintenance will be coordinated with FPOM.

9.8.2. Spring Spill (Table 4): 125% gas cap up to a maximum of 150 kcfs for fish passage spill (see section 2.1), 24 hours/day, April 10–June 15.

9.8.3. Summer Spill (Table 5):

- June 16–August 31: 95 kcfs, 24 hours/day.

9.8.4. Operational Considerations:

- Maximum fish passage spill level is 150 kcfs. This constraint is based on physical model observations indicating an increased incidence of rock deposition into the spillway stilling basin at spill ≥ 150 kcfs, which has caused erosion to the structure in the past.
- Minimum spill level is 50 kcfs; however, as observed in past years, to provide acceptable juvenile fish egress conditions in the tailrace under extreme low flow conditions, lower spill levels may be considered and coordinated through the TMT and/or FPOM.
- Actual hourly average spill levels at Bonneville Dam may range up to ±3 kcfs according to spill pattern tables in FPP Chapter 2.

10. FOP IMPLEMENTATION REPORTING

The Corps posts monthly FOP Implementation Reports between April and November on the following website: https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/ The updates include monthly project plots containing the following information:

- total flow: the total hourly river flow rate;
- generation flow: the hourly flow through the powerhouse turbine units;
- target spill: the spill target for that hour (Tables 3, 4 and 5);
- adjusted spill: the hourly spill level that can be achieved taking into consideration that spill may vary as a function of total river flow, forebay elevation, and generator capacity, and is subject to routine operational adjustments that limit the ability to spill to the target spill (see section 4.1);
- actual spill: the hourly flow over the spillway;

- resultant 12-hour average TDG for the tailwater at each project;
- reservoir elevation: the hourly reservoir forebay elevation;
- MOP: the target forebay elevation range; and,
- adjusted MOP: the adjusted MOP elevation range necessary to maintain project criteria. Adjusted can mean "raised" or "expanded" as specified in Section 4.

The reports also provide information on non-routine or unplanned operational adjustments that arise during the spill program and address any spill or MOP adjustments due to emergency situations (such as unplanned maintenance or outages), and for contingency operations for transmission reliability. See section 4.1 for more information.

The Corps provides the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Hourly flow, generation flow, and spill quantity data for the lower Snake and Columbia River dams are posted to the following website:
    - https://public.crohms.org/report/projdata.htm (web reports with the most recent 8 days of hourly project data and the current month of daily project data).
    - https://public.crohms.org/tmt/wq/historical/ (links to historic hourly project data files in .csv format organized by month back to 2004 including temperature and TDG information).
- Water quality data are received via satellite from TDG Fixed Monitoring Sites (FMS) in the Columbia and Snake rivers every hour and placed on a Corps public website upon receipt. Hourly TDG and water temperature data are posted to the following websites:
    - https://public.crohms.org/report/total.html (web reports with hourly TDG, project outflow and spill for the previous 3 days).
    - https://public.crohms.org/ftppub/water_quality/tdg/ (links to historic hourly water quality data files for each FMS including barometric and total gas pressure, TDG and project outflow and spill in csv-format organized by month back to 2005).
    - Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps calculates the applicable average TDG levels based on the Oregon and Washington water quality standards. These averages are reported at: https://public.crohms.org/ftppub/water_quality/12hr/.
- Spill cap information is posted to the following site each day: https://public.crohms.org/tmt/documents/ops/spill/caps/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-153:
Emergency Protocols for the Columbia River System

Appendix 1

Technical Management Team Emergency Protocols

COLUMBIA RIVER SYSTEM

FOR ATTACHMENT TO THE
WATER MANAGEMENT PLAN
AND OTHER APPROPRIATE ACTION PLANS

Updated December 5, 2025

1. Introduction

This document establishes a protocol that will be used by the Action Agencies for notification, consultation, and documentation in the event of an emergency concerning the operation of the Columbia River System (CRS) that impacts fish protection measures contained in the respective Biological Opinions (BiOps). The BiOps call for an annual Water Management Plan (WMP), which provides the detailed description of operations, based on the current year conditions, to ensure fish protection measures are consistent with Endangered Species Act responsibilities. This Protocol is meant to be general enough to encompass most kinds of emergencies. This Protocol pertains to short duration (approximately 1-7 days) interruptions or adjustments to protection measures for listed species that occur during the operation of the CRS.

The primary emergency types these protocols apply to are:

- Generation Emergency: the potential for or actual insufficiency of electrical generation to satisfy electrical demand or load.
- Transmission Emergency: the potential or actual loss or limitation in the ability to move electricity from the site of generation to the actual consumer or end-user.
- Fish Emergency: Unexpected equipment failures or other conditions that result in an interruption of fish protections measures.
- Other Emergency: the existence or result of extenuating circumstances which fall outside the range of normal operations, is unanticipated, and may significantly impair the ability to provide for other project uses, such as flood control or navigation, significant human health and safety concerns, or result in catastrophic impact, physical damage or failure to a dam, or other part of the physical power system. Examples include earthquakes, flood control operations, fires, navigation, dam safety, and failure of fish facilities infrastructure.

Specific Action Plans will be developed for Generation *(Completed-See Attachment 1)*, Transmission and Fish Emergencies that identify pre-emptive actions and emergency actions that will be taken consistent with this Protocol. Examples of thresholds for these types of emergencies are shown in the respective Action Plans contained in Attachments 1 and 2 of this Protocol. Action Plans are coordinated in the TMT process.

The degree and/or nature of any emergency ranges from those that require immediate action to those that are amenable to coordination among affected parties prior to action. In some instances, it is possible to plan for and develop procedures to respond to an emergency, while in other instances this is not possible. In addition, while many types of emergencies can be described for purposes of this Protocol, not all emergencies can be identified prior to the actual occurrence. Discussion of emergencies with effects of exceptional magnitude or duration will include involvement of regional executives.
Emergency actions will not be taken in place of long-term investments necessary to allow full uninterrupted implementation of the planned reservoir and dam operations while maintaining other project purposes.

Interruptions to protection measures for non-listed species are inclusive in these Protocols; however, priority will be given to protection measures for listed species.

2. Goals

The primary goal of this Protocol is to have written procedures that describe how the Action Agencies will manage the CRS to avoid or minimize emergencies impacting fish protection measures in accordance with ESA biological opinions and other operative documents such as the WMP, and provide timely communication and coordination with the TMT when they occur. When emergencies occur, the Action Agencies will work with TMT to restore the protection measures and provide the planned life cycle survival rates with priority given to in-time and in-place actions to the extent practicable. (*This does not create legal rights or obligations on the part of any party.*)

3. Definitions:

Emergency – A sudden, urgent, usually unforeseen occurrence or occasion requiring immediate action. As applied to this Protocol: when necessary, interruptions or adjustments occur to fish protection measures identified in the applicable biological opinions, the Annual Water Management Plan, and other operative documents.

Emergency Actions- Actions taken by the Action Agencies in response to an emergency that affects fish protection measures.

Action Agencies - Bonneville Power Administration (BPA), Corps of Engineers (COE or Corps), and the Bureau of Reclamation (BOR or Reclamation)

TMT - Technical Management Team is one of the Regional Forum technical teams. Adaptive management of the CRS is coordinated in the Technical Management Team public meeting process.

Water Management Plan. - The Water Management Plan (WMP) describes how the Action Agencies plan to operate the Columbia River System (CRS) projects in accordance with the governing documents identified in Section 2 of the TMT Annual Water Management Plan.

4. Emergency Protocol

4.1. Advanced Planning – Pre-Emptive Actions

When the operation of the CRS is likely to require implementing emergency actions and the event can be anticipated approximately 24 hours in advance or earlier, the Action Agencies will convene a meeting of the TMT to discuss actions to undertake with the objective of averting or minimizing impacts to fish protection measures. This Protocol contains an Action Plan (see Attachment 1) that describes pre-emptive actions that will be pursued to avoid interrupting fish protection measures.

When conditions are identified that could potentially require the use of Emergency Actions within approximately 24 hours, the responsible agency, i.e. the Action Agency which would declare the emergency, shall notify the chair and co-chairs(s) of the TMT as soon as the

situation is observed. If there is time, a TMT call or meeting will be arranged by the TMT chair or co-chair(s). If time allows, a discussion will be arranged, however, in some situations, the call may provide notification to TMT members of pre-emptive actions the responsible agency has deemed necessary.

The Action Agencies will implement all available pre-emptive actions prior to implementing emergency actions, and when feasible, the Action Agencies will implement alternate operations recommended by TMT.

4.2. Emergency Response

Emergency actions may be required as an immediate response if the pre-emptive actions fail to resolve the situation or the situation deteriorates without warning. If emergency actions are implemented as an immediate response an emergency will be declared. The Agency declaring the emergency will consider the prioritized emergency action lists provided in appendices of this Protocol, direction from TMT or other groups, standard operating procedures for specific projects, and/or guidance from appropriate responsible agencies to resolve the condition.

The Action Plans provided in the appendices of this Protocol have been discussed in the TMT forum will be used as guidance when events unfold too quickly for pre-coordination to occur. For emergencies requiring immediate action by those operating the respective hydropower project(s) or other elements necessary to sustain the function of the hydrosystem, after stabilizing the situation they will contact the chairs of the TMT and IT. The TMT chair or co-chair(s) will disseminate a notification via phone calls and emails to a "first contact list," which will include designated members from TMT and others that have requested inclusion on the first contact list as soon as practicable, but not later than the next working day. A meeting of the TMT will be convened at the earliest time available after notification of the first contacts.

5. Documentation and Follow Up Requirement

In all cases when emergency actions have been implemented, as soon as practicable, but not later than the next working day, the following information shall be provided by the agency declaring the emergency:

- Description of the emergency, how it occurred, and how long it is anticipated to last
- Description of how the emergency jeopardized system stability, public safety, or otherwise necessitated action that impacted fish protection measures.
- Identification of agencies that declared the emergency and agencies that responded to the emergency
- Identification of who was notified of the emergency
- Description of what actions were taken by each agency
- Identification of alternatives considered to reduce and offset impacts of the emergency.
- Further detailed information will be provided upon request of the TMT.

When requested by a TMT member, the TMT Chairperson will arrange for a follow-up TMT meeting or conference call to:

- Review status of the event,
- Ensure that all requirements for the implementation of emergency actions by the Action Agencies have been met and that all alternatives for offsetting adverse fish survival impacts of the implemented emergency actions have been considered, and
- Review the use of emergency action lists and revise the lists based on any lessons learned.

In general, system operations will revert to normal conditions, or as agreed upon in the TMT, when the event has been resolved or emergency actions are no longer required. The agency that declared the emergency will submit a detailed report of the incident and response at the next TMT meeting following the event unless other arrangements are arranged through the TMT process.

The Action Agencies will provide an opportunity for representatives of the region's affected parties to review the course of events and the implemented emergency actions to suggest refinements to the actions. These issues will be discussed at the next TMT meeting following the event.

6. Offsetting Adverse Effects of Emergency Response Actions

When emergency actions are implemented that cause adverse effects to fish protection measures, the TMT will assess the magnitude of the adverse effect and provide information on measures available to offset these effects. Alternative operations to offset adverse effects in-place and in-kind in a timely manner shall receive the highest priority. The members of the Regional Forum agree to cooperate in the development of this information for consideration through the TMT process.

When emergency actions impact a fish protection measure(s) included in a Biological Opinion, the appropriate agency (National Marine Fisheries Service (NMFS) or Fish and Wildlife Service (USFWS)) will consider the available information to assess whether the alternative operation used in response to the emergency situation is inconsistent with the relevant Biological Opinion(s), in that, in its expert opinion, the effects were in excess of what was contemplated in the analyses used in the respective biological opinion. If the alternative operation is determined to provide a reduction in the life cycle survival rate than that recommended in the Biological Opinion(s) analyses, then NMFS or USFWS will recommend to the federal operating agencies offsetting measures to ensure that the action satisfies Endangered Species Act requirements.

An Action Agency deciding not to provide offsets or proposing offsetting actions that are different from those recommended through the TMT process, will provide a written explanation for the record stating the decision and the basis for the decision.

Emergency Protocols Attachment

Attachment 1 – Power System Emergency Action Plan

Attachment 1

Power System Emergency Action Plan
December 5, 2025

If hydropower generation must be adjusted to support power system reliability, and this adjustment will alter planned fish operations specified in applicable biological opinions (and other guiding operative documents), Bonneville will attempt to implement the actions in the preemptive actions list below, where practicable. If these preemptive actions are unavailable, insufficient, or cannot be implemented in time, then Bonneville may implement additional actions as necessary to address the power system reliability need. The list of contingency actions below are examples of actions that can be taken to address the reliability conditions described in Section 4.4.2 of the FOP.

Where contingency action is necessary, notification to the region will be made as soon as practical, and will follow the protocols for notification, reporting, and documentation as specified in the *Technical Management Team Emergency Protocols, Appendix 1 – Emergency Protocols of the TMT Water Management Plan.*

Pre-emptive Actions (not in priority order)

- Purchase Energy and/or reserves at prices up to the applicable FERC WECC price cap.
- Request that Corps and Reclamation return all possible units to service by canceling or postponing scheduled generator or equipment outages (e.g., makes all units available).
- Request the transmission dispatcher consider adjusting transmission system maintenance or other possible actions that would allow increases or decreases in CRS generation as appropriate.
- Put into service (online) all possible generators (e.g., Grand Coulee pump-generators) while preserving sufficient energy storage to maintain reserve capability in subsequent hours
- Reshape flows within objectives at specific projects to meet immediate generation needs e.g., spill upstream projects to position water downstream.
- Cut any interruptible power commitments.
- Request adjustment of pumping schedule at Banks Lake.
- Request variance from non-power operational objectives or limits at CRS hydro projects (e.g., forebay draft limits, tailwater rate of change, recreation, irrigation, Treaty fishing, etc.)
- Reduce the amount of balancing reserves provided by the CRS to the minimum amount necessary for power system stability and reliability.
- Acquire any resources made available through the issuance of a "EEA Watch".
- After exhausting all available reserve sharing opportunities ask the transmission dispatcher to request the Reliability Coordinator to declare an Energy Emergency ALERT 1 when there is concern about sustaining required operating reserves.

Contingency Actions List

(Updated February 25, 2022)

When routine reliability tools and preemptive actions are insufficient or unavailable to resolve the power system condition, the following is a list of contingency actions that may be taken to provide reserves, voltage, energy or inertia. The order and extent of the actual implementation of the actions in this list will be dictated by each specific condition but if possible, the order at each individual dam will be followed. The actions on the list may be updated as necessary through coordination with TMT.

Contingency Actions are prioritized by tier and within each tier.

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 1	**Tier 1**	**Tier 1**	**Tier 1**
LWG Move Spillway Weir Hours within morning hours or next day morning	JDA shutoff adult attraction spill	**BON**: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1
LGS Move Spillway Weir Hours within morning hours or next day morning	BON shutoff adult attraction spill	**TDA**: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load
LMN Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts as coordinated with operators	**JDA**: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load
IHR Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates as coordinated with operators	**MCN**: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit
MCN Move Spillway Weir Hours within morning hours or next day morning	DWR: increase project drafts as coordinated with operators	**IHR**: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load
		LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load
		LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load
		LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load
		Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
JDA shutoff adult attraction spill	IHR 30% of flow	LWG reduce spill to 20 kcfs	LWG reduce spill to 20 kcfs
BON shutoff adult attraction spill	LMN 30 kcfs flat	LGS reduce spill to 30% of flow	LGS reduce spill to 30% of flow
HGH & LIB modify ramping rates	LGS 30% of flow	IHR reduce spill to 30% of flow	IHR reduce spill to 30% of flow
HGH, LIB, ALF, GCL : increase project drafts	LWG 20 kcfs	MCN reduce spill to 40% of flow	MCN reduce spill to 40% of flow
DWR: increase project drafts		JDA reduce spill to 30% of flow	JDA reduce spill to 30% of flow
		TDA reduce spill to 30% of flow	TDA reduce spill to 30% of flow
		BON reduce spill to 100 kcfs	MCN generate outside 1% up to full load
		MCN generate outside 1% up to full load	BON2 operate outside 1% up to full load
		BON PH2 operate outside 1% up to full load	Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG
		Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG	
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
BON1 shut off sluiceway	BON shut off sluiceway	LWG reduce spill to 18 kcfs	LWG 18 kcfs of spill
TDA shut off sluiceway	TDA shut off sluiceway	LMN reduce spill to 30% of flow	LMN 30% of flow
BON shut off B2CC	BON shut off B2CC	MCN reduce spill to 30% of flow	MCN 30% of flow
		BON 95 kcfs	BON 50 kcfs
		BON: Generate above 1% up to full load PH2	BON: Generate above 1% up to full load PH2

March 1 – April 2	April 3 – April 9	April 10 – June 15	June 16 – June 20
Tier 4	**Tier 4**	**Tier 4**	**Tier 4**
	LWG Reduce Spill to Spillway weir only	BON 75 kcfs	BON 75 kcfs
	LGS Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only	LWG Reduce Spill to Spillway weir only
	LMN Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only	LGS Reduce Spill to Spillway weir only
	IHR Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only	LMN Reduce Spill to Spillway weir only
		IHR Reduce Spill to Spillway weir only	IHR Reduce Spill to Spillway weir only
		MCN Reduce Spill to Spillway weir only	MCN Reduce Spill to Spillway weir only
Tier 5	**Tier 5**	**Tier 5**	**Tier 5**
	Reduce spill to zero at LWG	BON reduce spill to 50 kcfs	BON reduce spill to 50 kcfs
		BON reduces spill to zero	BON reduces spill to zero
	Reduce spill to zero at LGS	BON shutdown B1 Sluiceway	BON shutdown B1 Sluiceway
	Reduce spill to zero at LMN	BON shutdown B2CC	BON shutdown B2CC
	Reduce spill to zero at IHR		
Tier 6	**Tier 6**	**Tier 6**	**Tier 6**
		LWG reduce spill to zero	LWG reduce spill to zero
		LGS reduce spill to zero	LGS reduce spill to zero
		LMN reduce spill to zero	LMN reduce spill to zero
		IHR reduce spill to zero	IHR reduce spill to zero
		MCN reduce spill to zero	MCN reduce spill to zero
		JDA reduce spill to zero	JDA reduce spill to zero
		TDA reduce spill to zero	TDA reduce spill to zero

June 21 – August 14	**August 15 - August 31**	**September – November 15**	**November 16 - End of Feb**
Tier 1	**Tier 1**	**Tier 1**	**Tier 1**
BON: Generate above 1% up to full load PH1	**BON**: Generate above 1% up to full load PH1	LWG Move Spillway Weir Hours within morning hours or next day morning	HGH, LIB, ALF, GCL: increase project drafts
TDA: Generate above 1% up to full load	**TDA**: Generate above 1% up to full load	LGS Move Spillway Weir Hours within morning hours or next day morning	HGH & LIB modify ramping rates
JDA: Generate above 1% up to full load	**JDA**: Generate above 1% up to full load	LMN Move Spillway Weir Hours within morning hours or next day morning	BON shut off sluiceway
MCN: Generate above 1% up to 14.4 kcfs/unit	**MCN**: Generate above 1% up to 14.4 kcfs/unit	IHR Move Spillway Weir Hours within morning hours or next day morning	TDA shut off sluiceway
IHR: Generate above 1% up to full load	**IHR**: Generate above 1% up to full load	MCN Move Spillway Weir Hours within morning hours or next day morning	Dworshak increase project drafts
LMN: Generate above 1% up to full load	**LMN**: Generate above 1% up to full load		
LGS: Generate above 1% up to full load	**LGS**: Generate above 1% up to full load		
LWG: Generate above 1% up to full load	**LWG**: Generate above 1% up to full load		
Allow MOP excursion up to: 2 feet at IHR, LMN, LGS, and LWG (w/o reduction in FOP spill levels)	**BON**: Generate above 1% up to full load PH2		

June 21 – August 14	**August 15 - August 31**	**September – November 15**	**November 16 - End of Feb**
Tier 2	**Tier 2**	**Tier 2**	**Tier 2**
LWG Reduce Spill to Spillway weir only	LWG reduce spill to zero	JDA shutoff adult attraction spill	
LGS Reduce Spill to Spillway weir only	LGS reduce spill to zero	BON shutoff adult attraction spill	
IHR Reduce Spill to Spillway weir only	LMN reduce spill to zero	HGH, LIB, ALF, GCL : increase project drafts	
MCN 40% of flow	IHR reduce spill to zero	HGH & LIB modify ramping rates	
JDA 30% of flow	MCN reduce spill to zero		
TDA 30% of flow	JDA reduce spill to zero		
BON 75 kcfs	BON reduce spill to zero		
MCN generate outside 1% up to full load	TDA reduce spill to zero		
BON PH2 operate outside 1% up to full load			
Allow MOP excursion up to 3 feet at IHR, LMN, LGS, and LWG			
Tier 3	**Tier 3**	**Tier 3**	**Tier 3**
MCN 30% of flow	BON1 shut off sluiceway	LWG reduce spill to zero	
JDA Spillway Weir only	TDA shut off sluiceway	LGS reduce spill to zero	
BON 50 kcfs	BON shut off B2CC	LMN reduce spill to zero	
IHR reduce spill to zero		IHR reduce spill to zero	
LMN reduce spill to zero		MCN reduce spill to zero	
LGS reduce spill to zero		BON1 Shut off sluiceway	
LWG reduce spill to zero		TDA Shut off sluiceway	

June 21 – August 14	August 15 - August 31	September – November 15	November 16 - End of Feb
Tier 4	**Tier 4**	**Tier 4**	**Tier 4**
BON reduce spill to zero		DWR: increase project drafts	
TDA reduce spill to zero			
Tier 5	**Tier 5**	**Tier 5**	**Tier 5**
Tier 6	**Tier 6**	**Tier 6**	**Tier 6**

Definitions

Balancing Authority - The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area - The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load resource balance within this area.

BPA Power system – This term includes the Federal Columbia River hydropower projects and transmission system.

Energy Emergency Alerts – Procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. An Energy Emergency Alert may be initiated by Reliability Coordinator at the Reliability Coordinator's own request or upon the request of a Balancing Authority or a Load Serving Entity. See: https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf

Energy Emergency Watch - The EEA Watch is a communication tool that provides load serving entities a means to exchange information regarding issues that could impact the reliable operation of the power system when analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. This notice can be issued the day before the projected shortfall or if a sudden event occurs. Consumers are encouraged to conserve energy.

Energy Emergency Alert 1 - All available resources in use.

- Balance Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

Energy Emergency Alert 2 – Load management procedures in effect.

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customer' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments.

Energy Emergency Alert 3 – Firm load interruption imminent or in progress.

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Emergency Alert 0 - Termination

- When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the Energy Emergency be terminated.

Redispatch – The intentional incrementing of location-specific generation and the corresponding decrementing of different location-specific generation to mitigate loading on constrained transmission facilities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-154:
NWF v. NMFS Plaintiff Energy Declaration

THE HONORABLE MICHAEL H. SIMON

AMANDA W. GOODIN (WSB #41312)
agoodin@earthjustice.org
MICHAEL MAYER (WSB #32135)
mmayer@earthjustice.org
CHARISA GOWEN-TAKAHASHI (WSB #63091)
cgowentakahashi@earthjustice.org
Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340 | Phone

DANIEL J. ROHLF (OSB #99006)
rohlf@lclark.edu
Earthrise Law Center
Lewis & Clark Law School
10015 S.W. Terwilliger Boulevard, MSC 51
Portland, OR 97219
(503) 768-6707 | Phone
(503) 768-6642 | Fax

Attorneys for Plaintiffs

UNITED STATES DISTRICT COURT

DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, et al.

Plaintiffs,

and

STATE OF OREGON, et al.,

Intervenor-Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, et al.,

Defendants,

and

PUBLIC POWER COUNCIL, et al.,

Intervenor-Defendants.

Civ. No. 3:01-cv-00640-SI

DECLARATION OF NANCY HIRSH IN SUPPORT OF PLAINTIFFS' REPLY IN SUPPORT OF MOTION FOR PRELIMINARY INJUNCTION

I, NANCY HIRSH, state and declare as follows:

1. I was employed at the NW Energy Coalition (NWEC) from April 1996 through August 2025. For the first eighteen years I was the policy director and then in 2015, I became the NWEC executive director.

2. I have a Bachelor of Science in Natural Resource Policy from the University of Michigan's School of Natural Resources and the Environment.

3. During my tenure at NWEC, I have developed substantial expertise from analyzing utility and regional resource planning and engaging in regulatory proceedings, utility rate cases, and utility program reviews. I worked with state policymakers and state agency staff on energy policy, clean energy development, state energy strategy, and greenhouse gas emissions and air pollution reduction approaches. I have prepared detailed comments for submission to state agencies, policymakers, and regulators in Oregon, Washington, and Idaho on utility industry restructuring, resource planning, and clean energy development.

4. Between 1999 and 2011, I submitted multiple rounds of testimony to the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission as part of utility rate case proceedings for Puget Sound Energy, Avista Utilities, and Idaho Power. I also submitted testimony and substantive comments during utility resource planning, energy efficiency and utility merger dockets.

5. I have been invited to provide testimony before Congress on two occasions. First in 1997 before the House Committee on Resources, Subcommittee on Water and Power. The hearing was on the Status of the Regional Review Process for the Bonneville Power Administration (BPA). In 2001 I testified before the Senate Finance Committee regarding BPA's role in Infrastructure development, energy efficiency, and load management.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

6. In 2001, I assisted NWEC staff in the preparation of testimony in a BPA rate case (WP-02 Phase II). During my career I have prepared and submitted numerous comments to the NW Power and Conservation Council (NPCC) on the Comprehensive Regional Review, the Future Role of BPA in Power Supply, the Regional Dialogue proposal, and carbon emissions, among others. Through this work, I have developed a reasonably detailed understanding of the role BPA plays in energy marketing and transmission in providing electricity to the people of the Northwest and the role of the federal dams on the Columbia and Snake Rivers.

7. In 2008, I was asked by Idaho Governor Otter to serve on the Idaho Strategic Energy Alliance. Since 2019, I have served on the Advancement Board of the Institute for Energy Studies at Western Washington University. In 2020, I was asked by Washington Governor Inslee to co-chair the advisory committee helping to develop the 2021 State Energy Strategy.

8. I reviewed declarations submitted by BPA staff – Rachel Dibble, Bartholemew McManus, and Audrey Stevenson.

9. In this declaration I will discuss my review of recent NPCC and the Pacific Northwest National Lab's analysis on the following topics: A) Resource adequacy of the power system under fish operations; B) Fish operations impact on energy and peak needs; C) BPA has Many Tools to Provide Flexibility, Balancing and Operational Reserves; D) Lower Snake River & Lower Columbia projects contribution to system balancing; E) Power system support for the Tri-Cities; F) Handling extreme weather events; G) Maintaining affordability.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

A. The Most Recent NPCC Power Supply Adequacy Assessment Shows that the Fish Operations, Including Those Similar to the Operations NWF Seeks in its Preliminary Injunction, Do Not Have a Substantial Impact on Resource Adequacy.

10. The NPCCis an interstate compact agency established by Congress in the 1980 Northwest Power Act.[1] The four state (Washington, Oregon, Idaho, Montana) agency is tasked with regional power system planning, establishing resource priorities for BPA and regularly conducting an assessment of electricity adequacy. On a five-year cycle, the NPCC and its staff experts prepare a twenty-year regional power plan that evaluates loads and supplies to determine the least cost resource needs for meeting future loads while maintaining system reliability. As part of this five-year cycle, the NPCC and its staff also prepare a Columbia River Basin fish and wildlife program to address the regional needs of fish and wildlife impacted by the federal hydropower system pursuant to the Northwest Power Act's requirement that this program mitigate and enhance the Basin's fish and wildlife resources, especially salmon and steelhead and provide "equitable treatment" for these resources while also ensuring an adequate, efficient, and economical regional power supply. Hydropower system operations to manage fish and wildlife issues are an important factor in the regional power planning analysis and are critical to assuring a reliable power system.

11. In 2011, the NPCC adopted a resource adequacy standard of 5-percent annual "loss of load probability" (LOLP) to determine if the region had sufficient resources to meet regional loads during periods of high demand on the system like winter cold snaps or summer heat waves or when major generating units like the nuclear plant at Hanford have to go off line for some reason. One of its tools to check adequacy by predicting the LOLP for different scenarios is a computer model that projects operations of the power system – both supply

[1] www.nwcouncil.org

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

(including from the Columbia and Snake River dams) and demand – over many different future simulations (the GENESYS model). The GENESYS model (**Gen**eration **E**valuation **Sys**tem) was developed by NPCC in 1999 to replace earlier load-resource balance analysis. GENESYS uses a random probability analysis applied to a number of key variables, (e.g. loads, water levels, generation resources, energy efficiency) on a monthly operations basis. In 2019, the NPCC completed a substantial redevelopment of GENESYS to provide hourly analysis of operations, more granular/individual power plant dispatch, interactions between reserves and system optimized dispatch, and more interactive inclusion of regional and western power market dynamics.[2]

12. In 2022-2023, the NPCC recognized the increased complexity in the regional power system with more variable renewable energy resources, and a need for an even more sophisticated and precise approach to evaluate resource adequacy for the region. The NPCC made another round of significant changes to the GENESYS model and created a multi-metric adequacy framework to provide more detailed information about future demand and power supply needs to power system operators on the potential frequency, duration, and magnitude of shortfall events (i.e., time of high demand and limited supply) so they can plan for and mitigate risk with actions as well as determine the appropriate emergency measures to implement if necessary in order to avoid a significant loss of load (a power blackout of significant scope and duration).[3] This more sophisticated multi-metric approach has replaced the relatively simple

[2] https://www.nwcouncil.org/2021powerplan_genesys-model/

[3] https://www.nwcouncil.org/fs/18853/2024-4.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

single metric LOLP approach in the NPCC's most recent analysis for its forthcoming Ninth Power Plan as described on the NPCC's Resource Adequacy webpage.[4]

13. In the most recent update in 2024, NPCC's Pacific Northwest Power Supply Adequacy Assessment for 2029 used this new multi-metric modeling approach[5] and included the hydrosystem operation commitments from the 2023 Resilient Columbia Basin Agreement (RCBA) that were implemented during the stay of litigation. These commitments made a number of changes to dam and river operations to better support fish recovery efforts at the eight lower Snake River (LSR) dams and the lower Columbia dams.

14. As NPCC has explained in this and previous adequacy assessments, predicted shortfalls or adequacy concerns using any metric "does not necessitate an actual blackout will take place."[6] A shortfall in the adequacy modeling would signal the need for additional actions to be taken to avoid power disruptions, such as increased market purchases, mobilizing back-up generation, ramping up higher cost generation, suspension of fish protection operations, or calls for energy conservation or curtailment.

15. What is noteworthy in the analysis for the Adequacy Assessment for 2029 are the significant changes the NPCC made to reflect the broad challenges of matching the power supply with demand across a wide range of possible futures facing the region. As can be seen in Figure 8, the NPCC staff made adjustments due to significant new load growth from data center development and electrification, new transmission line development, coal-to-gas power plant

[4] https://www.nwcouncil.org/energy/energy-topics/resource-adequacy/

[5] Ibid, page 9.

[6] Ibid, page 9.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

conversions, RCBA hydro operations, and new planned resources available to meet overall system needs.

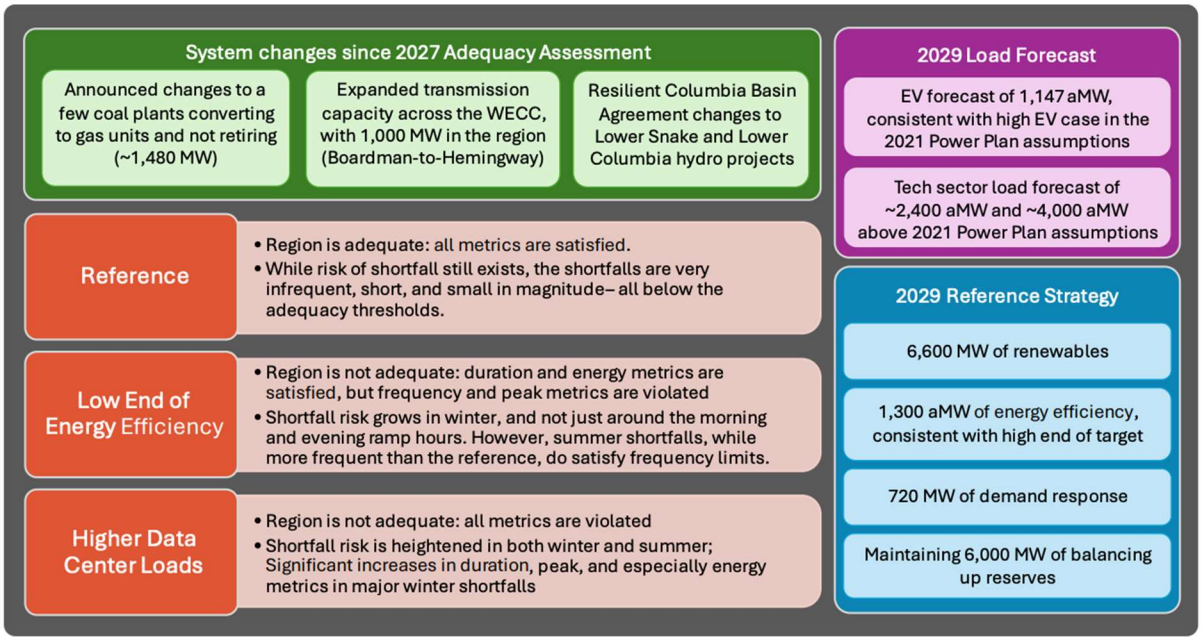


Figure 8. High-level summary of 2029 Adequacy Assessment

16. After including the RCBA operation changes to hydro operations, NPCC ran its power system adequacy assessment for 2029. The report states that "while hydropower is slightly reduced, …the changes do not lead to a significantly different regional adequacy result."[7] The model shows that the system adjusts to the RCBA dam and river operations by making a small increase in thermal generation and market purchases, particularly at night. The market purchases are within the market reliance limit set for the region. In the 2021 Power Plan, the NPCC set a power import limit to assure that the Northwest did not over rely on market purchases to satisfy resource needs.[8] Finding the RCBA operations are within the market reliance limit means that in

[7] Ibid, Page 22.

[8] https://www.nwcouncil.org/2021powerplan_change-reliance-extra-regional-markets-resource-adequacy/#:~:text=Our%20baseline%20setup%20limits%20the,Energy

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

the NPCC's assessment, it is reasonable to assume that market purchases will be available to compensate for any small decrease in hydro generation due to RCBA operations in the context of the full system operations and regional demand.

17. The Adequacy Assessment for 2029 indicates that inclusion of the hydro operations from the RCBA are relatively insignificant given the magnitude of forecasted load growth changes and emphasizes the critical need for the region to accelerate deployment of energy efficiency, new renewable resource development and transmission system expansion. Further, the assessment concluded that the region could meet the NPCC's multi-factor reliability standards under all but two of the scenarios that were examined. The first assumes low acquisition of energy efficiency and the second assumes high case data center development (Table 7).[9]

Table 7. Adequacy metric results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	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	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MW	0	4,196	196,324

18. For comparative purposes only, the NPCC staff note that if the multi-metric approach was compared to the LOLP, the reference case in the Adequacy Assessment for 2029,

[9] https://www.nwcouncil.org/fs/18853/2024-4.pdf, page 27.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

which includes the RCBA operations, would be a 2.2% LOLP. The low EE resulted in a LOLP of 7.8%[10] and the high data center scenario increased the LOLP to 13.3%.[11]

19. BPA's results are significantly different than the NPCC analysis. In Rachel Dibble's declaration[12] (para. 29), she describes BPA's use of GENESYS to determine the LOLP with different hydrosystem operations. In Table 1 (below) and in para. 31, Dibble concludes that all the hydrosystem operation scenarios would result in significant reliability challenges with LOLP's at 15% for the 2026 Fish Operations Program, 18% for the 2020 BiOp (called 2020 CRSO EIS ROD) and because the preliminary injunction "will reduce power generation and thus result in a higher LOLP: 27 percent."[13] Dibble goes on to clarify in para. 65, that the preliminary injunction results in a 250 MW reduction in power generation. Based on the review of the NPCC analyses it is unclear how the modest loss of generation results in such a dramatic increase in LOLP.

20. In fact, Dibble does not provide the assumptions, metrics, or scenarios that BPA used as inputs to GENESYS or the version of GENESYS that BPA used. Based on the output of the "LOLP" metric in BPA's results, which NPCC has replaced in the newer and more sophisticated version of GENESYS as discussed above, it appears that BPA may not have used the most recent multi-metric approach that NPCC now uses. Without meaningful or complete information on the assumptions, methods, or scenarios used in Dibble's modeling, it is

[10] Ibid, page 27.

[11] Ibid, page 28.

[12] 1404 2574 2025.12.16 Declaration of Rachel Dibble.pdf

[13] Ibid, Page 19, Para 31.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

impossible to determine why her modeling reached such different results from NPCC staff's comprehensive resource adequacy analysis and modeling of RCBA operations.

21. As a reminder, the NPCC Adequacy Assessment for 2029 shown in Figure 8 above states that the reference case was "below the adequacy thresholds" using an arguably more stringent RCBA hydro operations than BPA used in its Table 1 GENESYS modeling. The Adequacy Assessment for 2029 also assumes that the new resources identified in the NPCC's 2021 regional Power Plan[14] would be developed in a timely manner. This plays a significant role in ensuring that all the power supply adequacy metrics are met.[15]

22. Separate from this Adequacy Assessment for 2029, as part of the development of the Ninth Power Plan, the NPCC staff are beginning to evaluate future energy needs. As part of this work, NPCC staff recently modeled the effect of the impact of different hydrosystem operations for fish passage, coupled with the needs assessment, on power generation and reliability, among other metrics. In the NPCC staff Needs Assessment for Changing Hydro Operations Scenario, presented to the full Council on October 14, 2025[16], staff ran four different fish operation sensitivities against the 20-year forecasted needs of the power system through the updated GENESYS model. The four sensitivities analyzed by NPCC staff are: 2020 BiOp Operations ("current operations"); 2023 RCBA Operations; Fish managers Recommended Operations for MOP/spill (which is called "New MOP" and is virtually identical to the NWF's preliminary injunction request and Oregon's proposed preliminary injunction order); and Limited

[14] https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

[15] Pacific Northwest Power Supply Adequacy Assessment for 2029, NPCC 2024-4, page 35.

[16] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

Daily Flexibility (which starts with the 2020 BiOp as the base and then limits flexibility to reduce ramping).[17]

23. All of the fish operations analyzed including the "New MOP" sensitivity show very similar reliability results for power system operations, including the frequency and duration of events that risk a power supply shortfall. Critically, these winter and summer peak needs are extremely comparable across each of the modeled hydrosystem operations to address fish needs -- and the fish operation scenario that represents the preliminary injunction actually is predicted to perform *better* for reliability across seasons because the number of events and magnitude of the energy shortage events are lower for the New MOP than the BiOp or the RCBA using the "mixed bag" pathway with the 2031 load forecast, as shown in the chart below.[18]

Overall Results Compared to Metrics

	Frequency			Extreme Deficits		
	Annual LOLEV (events)	Winter LOLEV (events)	Summer LOLEV (events)	VaR Duration (hr)	VaR Peak (MW)	VaR Energy (MWh)
Adequacy Criteria	0.2	0.1	0.1	8	1,200	9,600
BiOp	218	61	75	22	9,681	354,192
RCBA	210	57	85	21	10,366	348,771
New MOP	189	59	55	21	8,917	326,858
Limited Flex	168	49	53	22	10,200	327,008

Northwest Power and Conservation Council 91 The 9th Northwest Regional Power Plan

Again, these predicted reliability events do not mean a blackout will occur. Instead, they are projected as part of power system planning to evaluate and prepare for the amount of proposed

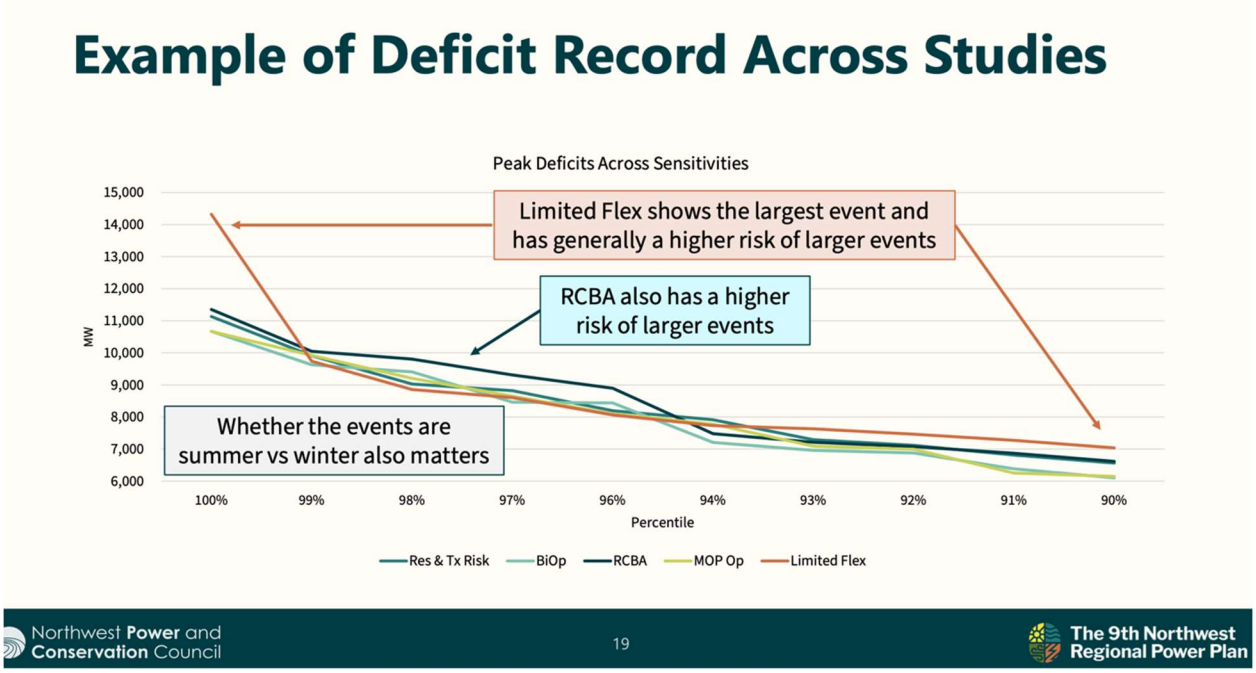
[17] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf (page 6).

[18] Ibid, Slide 91.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

new resource expansion or other power supply action (e.g., additional energy conservation) to address the events.

24. In January 2026, NPCC staff reran GENESYS after catching an error in irrigation demand.[19] This updated modeling shows similar results to the October 2025 hydro ops needs analysis which is that the region's projected large load growth will drive the need for new resources to meet winter and summer energy and peak capacity needs. On slide 19 (below), the revised modeling shows that the MOP sensitivity has fewer reliability events that are of less magnitude. This is a similar outcome to the October results.

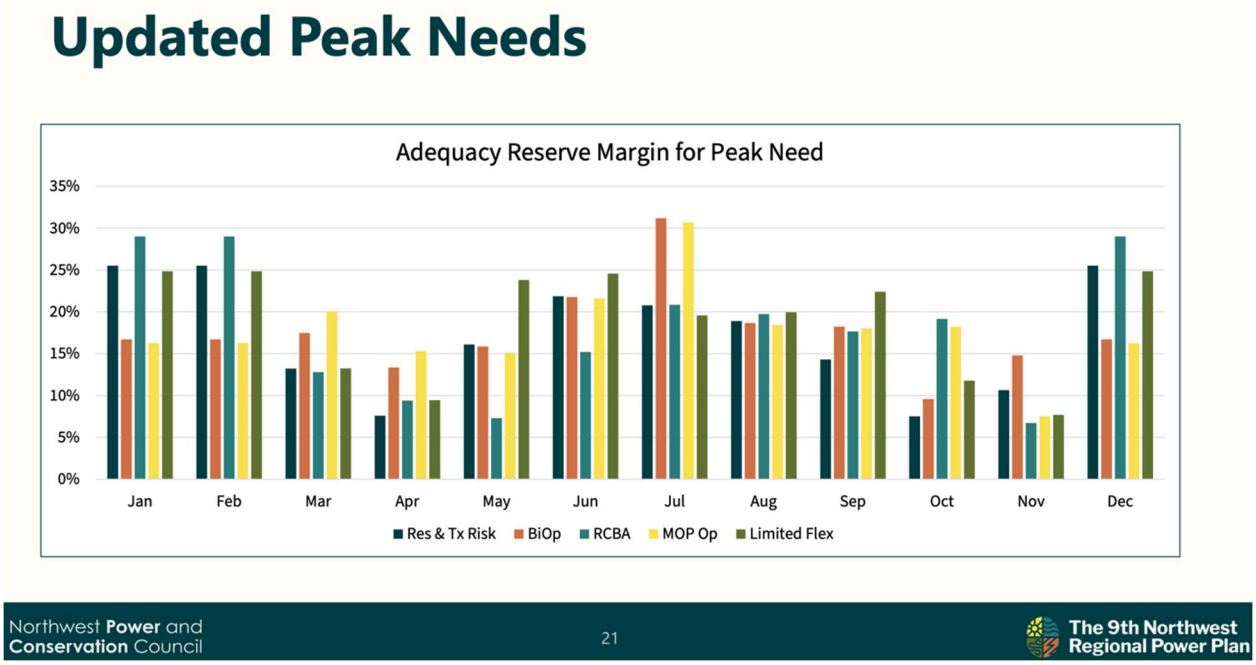


25. The NPCC staff go on to show how the corrected modeling impacts peak and energy needs across the year. While there are some variations across the different hydro operation sensitivities, the similarities are more striking than the differences. The New MOP operations do not create wildly different needs for additional peaking (Slide 21) or energy (Slide

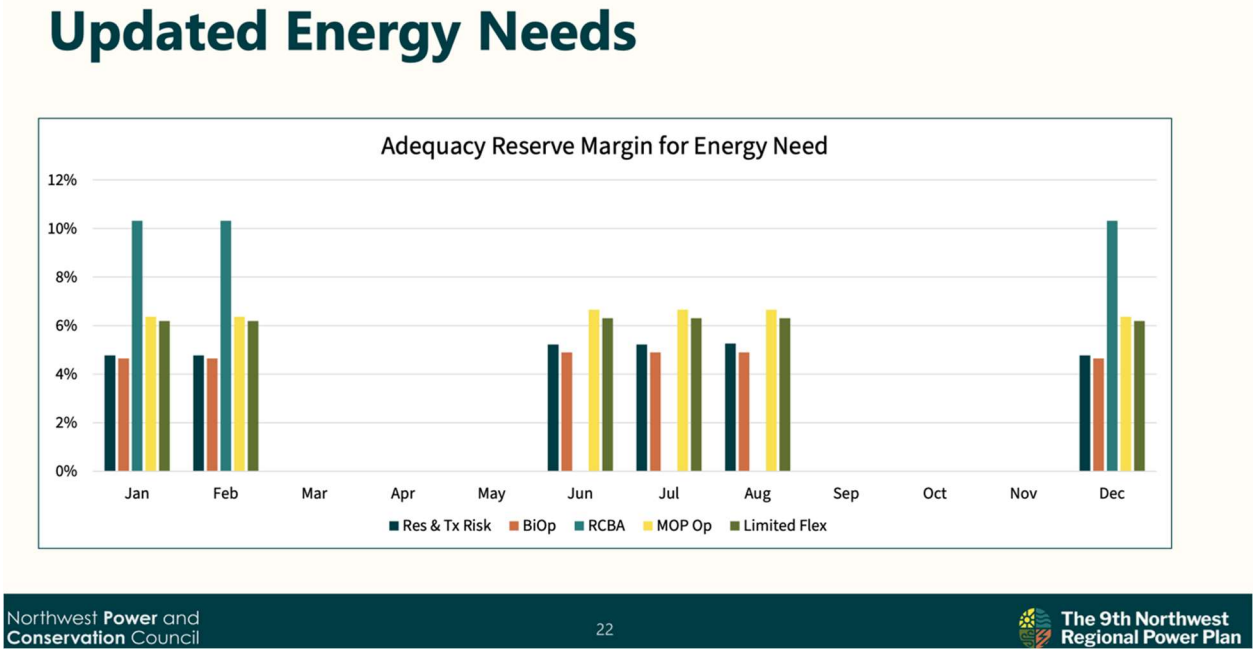
[19] https://www.nwcouncil.org/fs/19713/2026_01_3.pdf Pages 15-22.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

22) resources. As described in more detail below, this modeling shows that significant new resources will be needed over the long-term under any fish operations scenario, and that changes in demand (including changes driven by load growth, decarbonization, and data centers) are the drivers for these substantial long-term resource needs. The different fish operations scenarios do not significantly change the timing or magnitude of these long-term resource needs.



Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340



26. As expected, there are still significant needs (because the resource addition model has not yet been run to solve for the shown need) in the winter and summer months. For all resource adequacy assessments, the modeling does not indicate that these reliability events will happen, just that there is a probability that they could happen and BPA and utilities should take steps to be prepared to manage the system (and add new resources as needed) to avoid these adverse impacts.

B. NPPC Analysis Shows that the Differences Between Fish Operations are Minor for Energy Needs and Peak Capacity Needs.

27. As part of the Ninth Plan development, NPCC staff put together a comprehensive needs assessment based on expected growth in loads from data centers, electrification and economic/population growth. It is expected that the needs assessment will indicate that the regional power system will need to develop thousands of megawatts of new resources to meet

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

growing energy and winter and summer peak demands.[20] The range of hydrosystem operations from the 2020 BiOp, RCBA or proposed injunction do not materially affect the actions the region needs to take to meet projected future demand.[21] The resource needs assessment built into GENESYS is then fed into the NPCC OptGen model[22] which is a capacity expansion model and it helps determine what mix of resources are needed to meet the adequacy requirements. It is expected that the NPCC will use all these analytics to recommend, in the Ninth Power Plan, that the region and BPA add new generation, demand management, energy storage, and energy efficiency to the system.

28. In the Needs Assessment for Changing Hydro Operations Scenario, the NPCC staff did a detailed examination of how the hydrosystem responded to four different hydro operations sensitivities and how those sensitivities impacted the system-wide needs assessment across 90 different system scenarios. In addition to resource adequacy, the NPCC staff also looked at the energy and capacity generation across the hydrosystem operations.

29. From the chart on Slide 14 the differences in the four sensitivities are clearly delineated, showing that the differences are at most modest. The New MOP includes one month of additional spill in August at the LSR dams, and one to one-and-a-half foot operating ranges at the lower Columbia and LSR dams during the Spring and Summer salmon migration seasons.

[20] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf Slide 83.

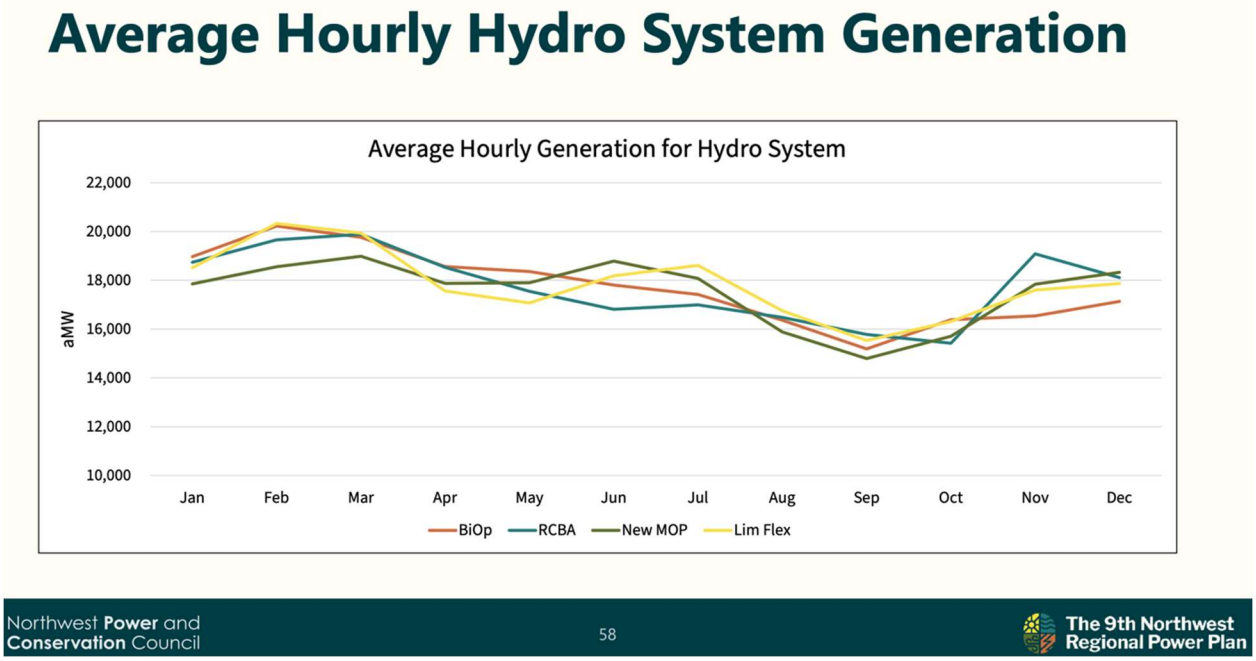
[21] Ibid, Slide 85.

[22] https://www.nwcouncil.org/fs/19331/2025_04_07.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

Sensitivity	Min Elevation	Elevation Target Sof-Constraint	Elevation Target Hard Constraint	Spill	Outflow Ramp	Reserves Allocation
2020 BiOp	2025 Water Management Plan (WMP)			BiOp spill	2025 WMP	Existing
2023 RCBA				RCBA spill	2025 WMP	Existing
New MOP & Spill	2025 WMP	+1 lower Columbia + 0.5 Lower Snake	+1.5 lower Columbia + 1 Lower Snake	RCBA spill with Aug 30 date	2025 WMP	Existing
Limited Flex	2025 WMP			BiOp Spill	2020-2024 avg.	Half

30. For the system as a whole, the NPCC analysis shows very modest difference in average hourly energy generation between the different fish operations.[23] The New MOP is slightly lower than the BiOp in January-April and September, but higher than the BiOp in May-July and November-December. The differences in all cases represent a small percentage of the total generation of the regional and federal power systems.

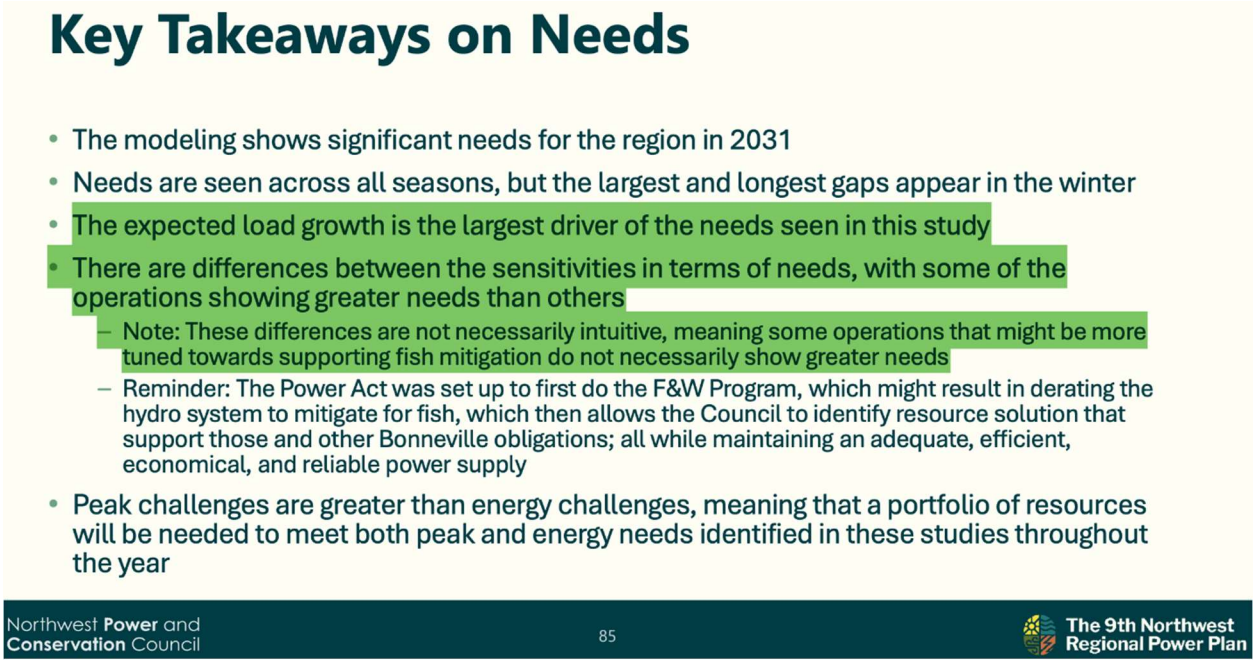


31. The NPCC Ninth Power Plan, which is under development and should be finalized in late 2026, is designed to assess existing and planned resources and the gap between

[23] Ibid, Slides 58 and 59.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

forecasted growth in demand and existing/planned resources.[24] The Ninth Plan will then recommend a portfolio of new resources to meet the forecasted demand growth and maintain a reliable power system. Projected load growth in power demand from data centers and electrification are the leading drivers of the need for new resources in the NPCC staff hydro operations and needs assessment. The analysis notes that some of the hydro operations that support fish recovery do not lead to greater resource needs.[25]



C. BPA has Many Tools to Provide Flexibility, Balancing and Operational Reserves

32. BPA operates 31 hydro projects as part of the federal hydrosystem across the region and has used all of the significant system flexibility to manage hydro operations for different fish survival regimes over the past decade to meet energy and capacity needs. In addition to the daily system operations activity that the BPA staff manage to provide a reliable

[24] https://www.nwcouncil.org/energy/ninthpowerplan/

[25] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf, Slide 85.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

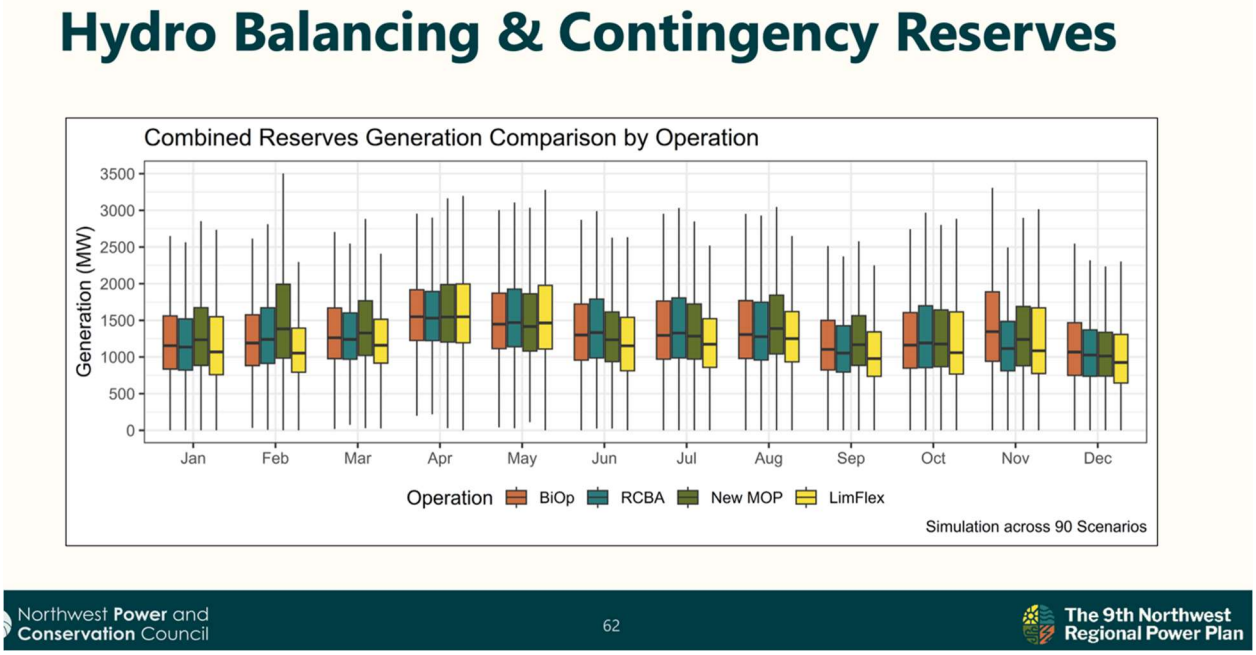
power system through many different kinds of system and operational constraints, there are other tools that BPA has and does use within and outside the federal system. These tools include, among others: Western Energy Imbalance Market, Fish Operations Plan variances, adding new strategic resources, and declaring an emergency. The point is, BPA has access to system flexibility and other flexibility tools to meet the kind of short duration supply constraints that the most recent NPCC modeling predicts under any hydro operations system while the agency and the region builds out new resources to meet load growth.

33. A key priority in system management is ensuring reserves. The NPCC hydro operations analysis in Slide 62 below shows very little difference across the four fish sensitivities and the 90 different simulation scenarios in terms of meeting requirements for overall system balancing and contingency reserves. February is the exception and it actually shows more generation across 90 scenarios from New MOP/preliminary injunction operations.[26] BPA's McManus' statement that there will be significant impact on balancing reserves (Page 8) is not evident in the NPCC modeling.[27]

[26] https://www.nwcouncil.org/fs/19637/2025_10_1b.pdf, Slide 62

[27] 1404 2579 2025.12.16 Declaration of Bartholemew McManus.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340



34. Interestingly, the LimFlex sensitivity, that the NPCC staff model, reduces the reserve allocation by half for the eight projects being impacted by fish operations (see the chart above at my para 26). In other words, for this modeling exercise, the NPCC staff assumes strict limits on the flexibility of these projects, and as a result they cannot provide as much reserve to the system. In the model, BPA still holds the same 4,000 MW of total reserve but not at these eight projects. NPCC staff note that the reserve needs are taken up in other places in the system.[28] This is evident in the results as the LimFlex contingency and operating reserves are not significantly different from the other operations, despite the limitation on flexibility (Slide 62 above). I do note that LimFlex is slightly more limited in the winter when water flows are more constrained. Overall, this indicates that BPA would be using the other tools at its disposal to address operational changes and in fact has been using those tools.

[28] Vimeo.com/1127583111 – starting time at 30:37 to 34:00

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

35. One of the most important tools available for meeting real-time energy balancing is the Western Energy Imbalance Market (WEIM) which includes 22 utilities across the West.[29] In the WEIM utilities and system operators can buy and sell power for load imbalances within fifteen-minute and five-minute intervals within an hour. This is a substantial market tool that provides significant support for balancing and flexibility needs. BPA joined the WEIM in 2022 and has seen significant financial and system operational benefits both in terms of purchasing power when demand spikes or when there is extreme weather and in terms of selling power to others when BPA has surplus supply to help with balancing the system. In fact, BPA's gross benefits from participation in the WEIM are equal to $25-$35 million/year.[30] It is notable that none of the BPA declarations by Dibble, McManus or Stevenson make mention of this important development for balancing power supply and demand.

36. Another tool to assist BPA with system operations are the variances and pre-coordinated operational changes used as part of the annual Fish Operation Plan (FOP) implementation. Attached hereto as Exhibit A is an Excel spreadsheet that summarizes my review of the data on variance and pre-coordinated operational changes for the past six years (2020 to 2025) to see how often variances and other operational changes were used to address energy or transmission (energy) related challenges.[31] The annual FOP reports show implementation changes from April to August in each year. The reasons for variances include human and program error, maintenance, navigation, and debris issues. The reasons for pre-coordinated operational changes include maintenance, navigation and transmission reliability.

[29] https://www.westernenergymarkets.com/western-energy-imbalance-market-weim

[30] https://www.westernenergymarkets.com/western-energy-imbalance-market-weim/benefits

[31] https://public.crohms.org/tmt/documents/FOP_Implementation_Reports/

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

All of these increases or decreases in spill occur at one hour increments up to 24 hours in a particular day. For the transmission reliability operational changes, the increases in spill are "to provide reserves." And the decreases in spill are "due to an increase in generation to deploy reserves."[32]

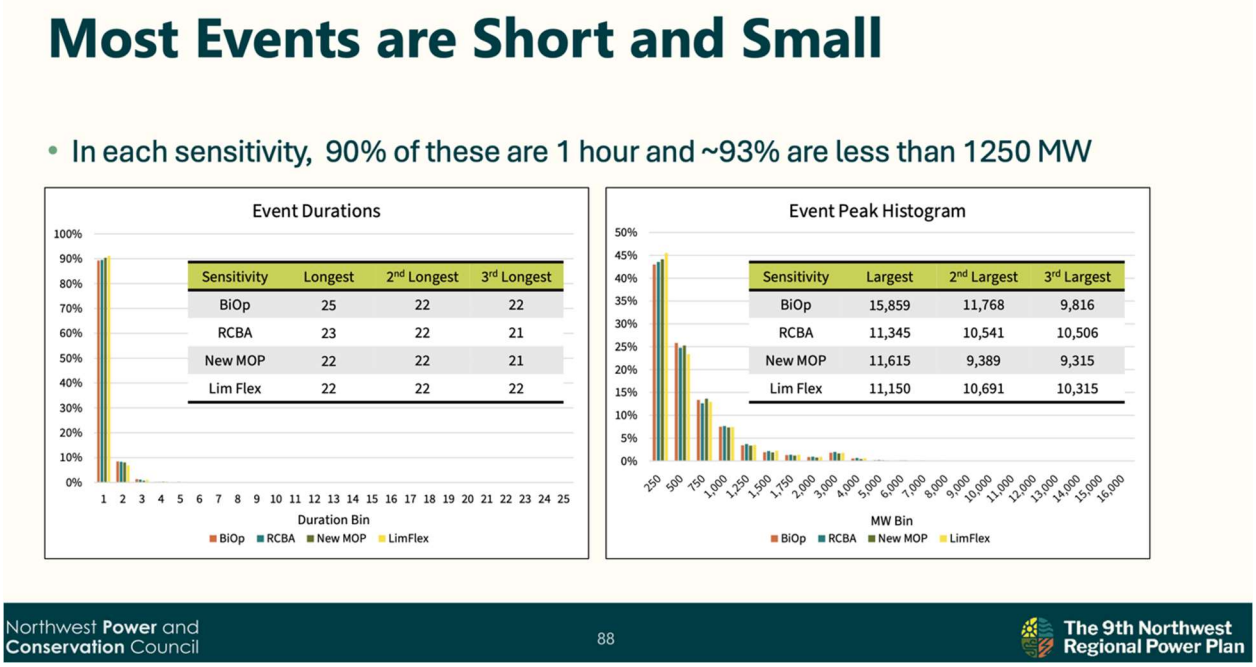
37. What is fascinating about this data is that spill operations were adjusted 3,786 hours during the five-year period for human/program error, maintenance, navigation, and debris management. Whereas spill operations were adjusted 483 hours during the five-year period for transmission reliability reasons. In 2024 and 2025, when the RCBA operations were in place, energy related changes occurred in only two hours in the period between April-August. Whereas in this same timeframe, the other reasons for change required 1,439 hours of variances and pre-coordinated changes.

38. The FOP variance data shows that many of the variances and pre-coordinated operational changes needed are for an hour. There is an interesting correlation between the use of the variances and changes and the NPCC hydro ops needs assessment which says that 90% of these reliability events are one hour in duration with another 8% at two hours in duration. Across the entire power system, 70% of the events are less than 500 megawatts and 93% of events are less than 1250 megawatts.[33] This indicates that routine short-duration variances may continue to be a useful tool to allow adjustments to meet any of the short-duration challenges that occur on BPA's system.

[32] Ibid, Page 6.

[33] http://nwcouncil.or/fs/19637/2025_10_1b.pdf Slide 88.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340



39. While it has been clear for some time that BPA and other utilities in the region will need to add new resources to maintain resource adequacy in the face of load growth and other long-term challenges facing the region, BPA has surprisingly not taken significant action to add new power system resources. Section 6 of the Northwest Power Act authorizes BPA to acquire new resources to meet its needs, including its fish and wildlife protection operations.[34] New resources developed under this authority would provide more system flexibility and minimize the occurrence of emergencies in the future.

40. Top of the list for new resources is maximizing energy efficiency and working with BPA customers to manage loads to reduce peaks. The potential for regional demand management development (to reduce peak demand and provide dispatchable resources during capacity needs) is very substantial. Since 2010 and the 6th Power Plan, the NPCC has been calling on BPA and the region to make investments in demand management (often called

[34] 839d(a)(2)(B). to assist in meeting the requirements of section 839b(h) of this title. [Northwest Power Act, §6(a)(2)(B), 94 Stat. 2717.]

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

demand response). The NPCC's 2021 Plan ramped this call up even more with estimates of about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential.[35] A large portion of NPCC's recommended demand response resources consist of rate design and conservation voltage reduction programs that can be implemented quickly and very inexpensively over the next several years. This recommendation is expected to be strengthened in the 9th Plan as the region considers increased pressure on Northwest resource adequacy and sufficient flows in the hydrosystem for fish and wildlife protection. Despite the long-standing push from the NPCC, BPA's 2022-27 Energy Efficiency Action Plan noted 300 MW of demand response resources, but made no commitment to achieve these flexibility resources, and only to engage with its customer utilities in exploring opportunities.[36]

41. Another critical new resource is battery storage. In the past 5-6 years, both Texas and California have added thousands of megawatts of battery storage to their systems to manage peak energy needs. Texas now has 15,000 MW.[37] California has grown its battery storage resource from 800 MW in 2019 to 17,000 MW in 2025.[38] Most of this storage in California is from utility scale systems. Within the region, between 2022 and mid-2025, Portland General Electric has moved forward with a total of 492 MW of battery storage capacity in four different facilities across its service territory to provide up to four hours of peak energy or to support PGE's system during extreme weather or unexpected disruptions.[39] While the Northwest has

[35] https://www.nwcouncil.org/2021-northwest-power-plan/ Page 64.

[36] https://www.nwcouncil.org/fs/18206/2023_03_p3.pdf

[37] https://ieefa.org/resources/summer-solar-and-battery-storage-records-texas

[38] https://www.energy.ca.gov/news/2025-11/californias-battery-storage-fleet-continues-record-growth-strengthening-grid#:~:text=WHAT%20YOU%20NEED%20TO%20KNOW,Gov.

[39] https://portlandgeneral.com/news/2025-08-pge-energizes-475-mw-of-battery-energy-storage-to-boost-grid

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

historically used the reservoir system as our utility scale storage battery, the writing has been on the wall for the past decade that that flexibility and capacity is increasingly constrained due to climate impacts on precipitation patterns, the needs of salmon and steelhead, and the needs to integrate variable renewable resources. Yet, BPA and much of the region have been very slow to develop battery storage projects, even short duration systems, to support fish operations and peak energy needs.

42. Throughout Dibble's declaration she states that BPA's only option to address the system flexibility needs and assure system reliability is to declare an emergency and suspend fish operations. I understand that the emergency protocols are available for emergencies to maintain power system reliability and are not intended as a way to provide regular operational system support. NWF's motion assumes that the emergency protocols remain in place and are a key tool to maintain reliability as are the more routine variances discussed above that do not require a declaration of power system emergency. By emphasizing the need for and consequences of an emergency declaration, BPA seems to overplay the loss of flexibility and ignore the flexibility created by other tools, from the WEIM to variances to changes across the rest of the system's operations.

D. The System Balancing Interaction Between LSR and the Lower Columbia Projects

43. I have reviewed a study conducted by the Pacific Northwest National Laboratory (PNNL) on the role of the four lower Snake River dams over a five-year time frame.[40] PNNL's analysis of operations at the four LSR dams, and the other mainstem Columbia dams over the 2020-2024 timeframe included fish operations in place during each of the study years. These

[40] September 2025, US Department of Energy, Lower Snake River Dams Contribution to Grid Services, https://www.osti.gov/biblio/3000013

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

operations included years when the 2020 BiOp operations and the RCBA operations were in place.

44. In the chapters on inter and intra hour ramping and balancing, PNNL shows that there is great consistency in the operation of the lower Columbia, LSR, Grand Coulee, and Chief Joseph projects to provide system flexibility across the five-year period and different hydro operations for fish recovery. The most significant variables to how the different projects are operated are energy market conditions and water levels, not reservoir elevations and spill regimes.[41]

E. Supporting the Tri-Cities

45. Providing reliable support service to the local load center of the Tri-Cities is vitally important. Ice Harbor generators provide voltage and reactive power support to the Tri-Cities. This type of support makes the power system more efficient, helps control and manage the oscillation in voltage that exists in an AC system and comes from synchronous generators like those at Ice Harbor. The PNNL study finds that "most, if not all synchronous generators operate in Automatic Voltage Regulation mode".[42] Voltage regulation and reactive power support are more a function of the physical presence of the generators at Ice Harbor dam rather than the level of spill or MOP conditions at Ice Harbor. Stevenson also recognizes the important role of Ice Harbor in providing support to the Tri-Cities[43], though her examples imply the loss of generation at Ice Harbor. The preliminary injunction in no way contemplates this outcome. In

[41] Ibid, Chapters 3.0 and 4.0

[42] Ibid, page 38

[43] 1404 2582 2025.12.16 Declaration of Audrey Stevenson.pdf Paragraphs 17 and 33.

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

addition, reactive power could be provided by locally sited storage and distributed generation, that may have fast response times and could provide additional reactive power support.[44]

46. Another option to support the Tri-Cities is grid enhancements, and BPA is already moving forward with some of these projects. However, the reliability support for the Tri-Cities has been a concern since the mid-2010s and it was not until 2023 that BPA launched the Tri-Cities Reinforcement Project.[45] The series of three grid reinforcement projects are very important and will help address these local reliability issues. Even before these projects are completed, however, the analysis performed by PNNL and the NPCC shows that power services to in the Tri-Cities will not be at risk from the preliminary injunction and that there are other resources that could be quickly deployed to address BPA's concerns.

F. Extreme Weather Events

47. Extreme weather events, both heat domes and arctic blasts, can happen in the Northwest and system reliability is vital during these challenging times. Recent experience has shown that extreme weather conditions do not usually occur across regions at the same time which allows the Northwest, California and the Southwest to share resources on the transmission interties and through the Western Energy Imbalance Market. This type of connectivity and coordination is important and BPA has planned for and effectively used these resources across regions during extreme events.

48. The PNNL study, for example, examined how BPA managed its system during the Northwest extreme winter event (January 2024 with RCBA fish operations in place). During

[44] https://rmi.org/clean-energy-101-how-batteries-can-support-grid-reliability/

[45] https://www.bpa.gov/-/media/Aep/efw/nepa/active/south-of-tri-cities/Tri-Cities-Reinforcement-Project-Fact-Sheet-2023-FINAL.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

the January 2024 arctic blast, Pacific Northwest loads went up dramatically and PNNL shows that BPA responded by ramping up generation at Grand Coulee from 2,000 MW to 3,500 MW and at Chief Joseph from 1,000 MW to 2,000 MW during time of peak demand (generally morning and evening hours). Low water conditions are normal in winter in the lower Snake River basin and the LSR dams provided their typical level of increased winter generation during a cold snap – about 1,000 MW total for specific peak hours within each day.[46] PNNL states that "due to water constraints, the LSR plants were unable to significantly increase their output beyond typical levels but still contributed approximately 1,000 MW during peak generation".[47]

49. BPA used the ramping flexibility of its system to increase generation for a couple of hours at a time during these extreme emergency situations. The PNNL study also shows the crucial importance of interconnection within the West as BPA used the WEIM to bring 3,675 MW of power north on the California-Oregon Intertie – more power than the winter hydrosystem could provide under any circumstances.[48]

50. In the Dibble declaration, there is extensive reference to extreme weather events and the risk to public health and safety. As demonstrated in the PNNL analysis, BPA has many tools available to manage extreme weather events, including emergency protocols that allow suspension of fish operations to ensure reliability of the system. BPA has successfully used the WEIM power market to both bring resources into the northwest during extreme weather events and to send power to other parts of the west during their weather events.

[46] Ibid, Page 58, Figure 7-3

[47] Ibid, Page 56

[48] Ibid, Page 59, Figure 7-6

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

G. Affordability

51. As I mentioned already, Dibble states that the proposed injunction operations will result in a loss of 250 average MW of power generation in fiscal year 2026. BPA's 2025 White Book[49] shows its total firm obligations to be approximately 8,000 aMW (with a high of 9,374 a MW in December and a low of 7,038 aMW in May).[50] Dibble's estimated lost generation of 250 aMW is approximately 3% of the yearly average MW generation for BPA. The White Book uses RCBA for hydro operations and the results state that in median water (50th percentile of system operations) there are annual energy surpluses throughout the 10-year planning period. However, BPA uses the 10th percentile of water flows (i.e., very low flow conditions) as its firm water conditions which results in annual deficits of 426 aMW to 1012 aMW.

52. In May 2025, BPA issued a letter to all Pacific Northwest utilities, and customers including outside the region customers, stating that it is "projecting that periodically through September 2026 BPA may have surplus power, capacity, and Transferred Frequency Response (TFR) available for sale."[51] While this notice is an annual notice of potential surplus resources, it is an indication that BPA has significant flexibility in how it utilizes the system to meet reliability requirements while also making additional sales to support increased revenue. Were BPA seriously concerned about the 15-27% LOLP presented in Dibble's declaration, this letter seems unusual at best.

53. On January 30, 2024, BPA Administrator John Hairston testified before the House Energy and Commerce Committee, Subcommittee on Energy, Climate and Grid Security

[49] https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf

[50] Ibid, Pages 15-16.

[51] https://www.bpa.gov/-/media/Aep/power/power-products-catalog/fy-26-notice-of-surplus-power.pdf

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

regarding the RCBA agreement and the impact on BPA.[52] Attached to Mr. Hairston's testimony is a spread sheet with BPA's preliminary rate assessment of the $300 million commitment in the RCBA combined with the rate impact of the operational changes in that agreement indicated an incremental rate impact per year of 0.05%. This increases power rates by $0.2 to $0.3/megawatthour. This spread sheet shows a line item for "Ops Ave. Revenue Increase" to estimate the financial impact of the operations included in the RCBA or stay of litigation. BPA estimated these rate impacts as generating an extra $1 million per year relative to the 2020 BiOp Record of Decision – in other words, BPA would *save* money by implementing these operational changes. The RCBA on the whole would impose only modest costs when the savings from changed operations are combined with the financial commitments BPA made in that agreement (which are addressed as separate line items in that spreadsheet, including "High Priority CBRI" and Lower Snake Comp Plan", together totaling $300 million over 10 years. BPA has abandoned the financial commitments in that agreement so the $300 million in increased costs over ten years are no longer affecting rates.[53]

Conclusions

54. Throughout Dibble's declaration, she uses significant hyperbole stating that the unprecedented proposed preliminary injunction will lead to power shortages and blackouts that will risk human health and safety and have significant economic damage to the region. Yet, after reviewing the NPCC Adequacy Assessment for 2029, the PNNL LSR assessment and the NPCC hydro operations analysis I conclude that the impact of the various fish operation regimes,

[52] https://www.energy.gov/sites/default/files/2024-01/January%2030%202024%20HEC%20BPA%20John%20Hairston%20Testimony%20Columbia%20River%20System_Final.pdf

[53] Ibid, Page 8 (page 2 of the spreadsheet).

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

including those NWF seeks in its preliminary injunction, have very modest impacts on power generation, peak needs, and overall ability to maintain a reliable power system. The preliminary injunction operations are similar to previous operations of the system over the past five years with some modest adjustments in spill and operating pool elevations to reduce the harm to migrating salmon and steelhead. BPA has experience with the spill and MOP conditions and has experience managing the power system with these conditions and providing the flexibility necessary to match power supply with demand. And if emergencies arise, the protocols for modifying fish operations remain available.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge.

Executed this 22nd day of January, 2026.



NANCY HIRSH

Earthjustice
810 Third Ave., Suite 610
Seattle, WA 98104
(206) 343-7340

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-155:
Centralia Output Data

	A	B	C	D	E	F
1	State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date
2	WA	Centralia	3845	BW21		1/1/2021
3	WA	Centralia	3845	BW21		1/2/2021
4	WA	Centralia	3845	BW21		1/3/2021
5	WA	Centralia	3845	BW21		1/4/2021
6	WA	Centralia	3845	BW21		1/5/2021
7	WA	Centralia	3845	BW21		1/6/2021
8	WA	Centralia	3845	BW21		1/7/2021
9	WA	Centralia	3845	BW21		1/8/2021
10	WA	Centralia	3845	BW21		1/9/2021
11	WA	Centralia	3845	BW21		1/10/2021
12	WA	Centralia	3845	BW21		1/11/2021
13	WA	Centralia	3845	BW21		1/12/2021
14	WA	Centralia	3845	BW21		1/13/2021
15	WA	Centralia	3845	BW21		1/14/2021
16	WA	Centralia	3845	BW21		1/15/2021
17	WA	Centralia	3845	BW21		1/16/2021
18	WA	Centralia	3845	BW21		1/17/2021
19	WA	Centralia	3845	BW21		1/18/2021
20	WA	Centralia	3845	BW21		1/19/2021
21	WA	Centralia	3845	BW21		1/20/2021
22	WA	Centralia	3845	BW21		1/21/2021
23	WA	Centralia	3845	BW21		1/22/2021
24	WA	Centralia	3845	BW21		1/23/2021
25	WA	Centralia	3845	BW21		1/24/2021
26	WA	Centralia	3845	BW21		1/25/2021
27	WA	Centralia	3845	BW21		1/26/2021
28	WA	Centralia	3845	BW21		1/27/2021
29	WA	Centralia	3845	BW21		1/28/2021
30	WA	Centralia	3845	BW21		1/29/2021
31	WA	Centralia	3845	BW21		1/30/2021
32	WA	Centralia	3845	BW21		1/31/2021
33	WA	Centralia	3845	BW21		2/1/2021
34	WA	Centralia	3845	BW21		2/2/2021
35	WA	Centralia	3845	BW21		2/3/2021
36	WA	Centralia	3845	BW21		2/4/2021
37	WA	Centralia	3845	BW21		2/5/2021
38	WA	Centralia	3845	BW21		2/6/2021
39	WA	Centralia	3845	BW21		2/7/2021
40	WA	Centralia	3845	BW21		2/8/2021
41	WA	Centralia	3845	BW21		2/9/2021
42	WA	Centralia	3845	BW21		2/10/2021
43	WA	Centralia	3845	BW21		2/11/2021

	A	B	C	D	E	F
44	WA	Centralia	3845	BW21		2/12/2021
45	WA	Centralia	3845	BW21		2/13/2021
46	WA	Centralia	3845	BW21		2/14/2021
47	WA	Centralia	3845	BW21		2/15/2021
48	WA	Centralia	3845	BW21		2/16/2021
49	WA	Centralia	3845	BW21		2/17/2021
50	WA	Centralia	3845	BW21		2/18/2021
51	WA	Centralia	3845	BW21		2/19/2021
52	WA	Centralia	3845	BW21		2/20/2021
53	WA	Centralia	3845	BW21		2/21/2021
54	WA	Centralia	3845	BW21		2/22/2021
55	WA	Centralia	3845	BW21		2/23/2021
56	WA	Centralia	3845	BW21		2/24/2021
57	WA	Centralia	3845	BW21		2/25/2021
58	WA	Centralia	3845	BW21		2/26/2021
59	WA	Centralia	3845	BW21		2/27/2021
60	WA	Centralia	3845	BW21		2/28/2021
61	WA	Centralia	3845	BW21		3/1/2021
62	WA	Centralia	3845	BW21		3/2/2021
63	WA	Centralia	3845	BW21		3/3/2021
64	WA	Centralia	3845	BW21		3/4/2021
65	WA	Centralia	3845	BW21		3/5/2021
66	WA	Centralia	3845	BW21		3/6/2021
67	WA	Centralia	3845	BW21		3/7/2021
68	WA	Centralia	3845	BW21		3/8/2021
69	WA	Centralia	3845	BW21		3/9/2021
70	WA	Centralia	3845	BW21		3/10/2021
71	WA	Centralia	3845	BW21		3/11/2021
72	WA	Centralia	3845	BW21		3/12/2021
73	WA	Centralia	3845	BW21		3/13/2021
74	WA	Centralia	3845	BW21		3/14/2021
75	WA	Centralia	3845	BW21		3/15/2021
76	WA	Centralia	3845	BW21		3/16/2021
77	WA	Centralia	3845	BW21		3/17/2021
78	WA	Centralia	3845	BW21		3/18/2021
79	WA	Centralia	3845	BW21		3/19/2021
80	WA	Centralia	3845	BW21		3/20/2021
81	WA	Centralia	3845	BW21		3/21/2021
82	WA	Centralia	3845	BW21		3/22/2021
83	WA	Centralia	3845	BW21		3/23/2021
84	WA	Centralia	3845	BW21		3/24/2021
85	WA	Centralia	3845	BW21		3/25/2021
86	WA	Centralia	3845	BW21		3/26/2021

	A	B	C	D	E	F
87	WA	Centralia	3845	BW21		3/27/2021
88	WA	Centralia	3845	BW21		3/28/2021
89	WA	Centralia	3845	BW21		3/29/2021
90	WA	Centralia	3845	BW21		3/30/2021
91	WA	Centralia	3845	BW21		3/31/2021
92	WA	Centralia	3845	BW22		1/1/2021
93	WA	Centralia	3845	BW22		1/2/2021
94	WA	Centralia	3845	BW22		1/3/2021
95	WA	Centralia	3845	BW22		1/4/2021
96	WA	Centralia	3845	BW22		1/5/2021
97	WA	Centralia	3845	BW22		1/6/2021
98	WA	Centralia	3845	BW22		1/7/2021
99	WA	Centralia	3845	BW22		1/8/2021
100	WA	Centralia	3845	BW22		1/9/2021
101	WA	Centralia	3845	BW22		1/10/2021
102	WA	Centralia	3845	BW22		1/11/2021
103	WA	Centralia	3845	BW22		1/12/2021
104	WA	Centralia	3845	BW22		1/13/2021
105	WA	Centralia	3845	BW22		1/14/2021
106	WA	Centralia	3845	BW22		1/15/2021
107	WA	Centralia	3845	BW22		1/16/2021
108	WA	Centralia	3845	BW22		1/17/2021
109	WA	Centralia	3845	BW22		1/18/2021
110	WA	Centralia	3845	BW22		1/19/2021
111	WA	Centralia	3845	BW22		1/20/2021
112	WA	Centralia	3845	BW22		1/21/2021
113	WA	Centralia	3845	BW22		1/22/2021
114	WA	Centralia	3845	BW22		1/23/2021
115	WA	Centralia	3845	BW22		1/24/2021
116	WA	Centralia	3845	BW22		1/25/2021
117	WA	Centralia	3845	BW22		1/26/2021
118	WA	Centralia	3845	BW22		1/27/2021
119	WA	Centralia	3845	BW22		1/28/2021
120	WA	Centralia	3845	BW22		1/29/2021
121	WA	Centralia	3845	BW22		1/30/2021
122	WA	Centralia	3845	BW22		1/31/2021
123	WA	Centralia	3845	BW22		2/1/2021
124	WA	Centralia	3845	BW22		2/2/2021
125	WA	Centralia	3845	BW22		2/3/2021
126	WA	Centralia	3845	BW22		2/4/2021
127	WA	Centralia	3845	BW22		2/5/2021
128	WA	Centralia	3845	BW22		2/6/2021
129	WA	Centralia	3845	BW22		2/7/2021

	A	B	C	D	E	F
130	WA	Centralia	3845	BW22		2/8/2021
131	WA	Centralia	3845	BW22		2/9/2021
132	WA	Centralia	3845	BW22		2/10/2021
133	WA	Centralia	3845	BW22		2/11/2021
134	WA	Centralia	3845	BW22		2/12/2021
135	WA	Centralia	3845	BW22		2/13/2021
136	WA	Centralia	3845	BW22		2/14/2021
137	WA	Centralia	3845	BW22		2/15/2021
138	WA	Centralia	3845	BW22		2/16/2021
139	WA	Centralia	3845	BW22		2/17/2021
140	WA	Centralia	3845	BW22		2/18/2021
141	WA	Centralia	3845	BW22		2/19/2021
142	WA	Centralia	3845	BW22		2/20/2021
143	WA	Centralia	3845	BW22		2/21/2021
144	WA	Centralia	3845	BW22		2/22/2021
145	WA	Centralia	3845	BW22		2/23/2021
146	WA	Centralia	3845	BW22		2/24/2021
147	WA	Centralia	3845	BW22		2/25/2021
148	WA	Centralia	3845	BW22		2/26/2021
149	WA	Centralia	3845	BW22		2/27/2021
150	WA	Centralia	3845	BW22		2/28/2021
151	WA	Centralia	3845	BW22		3/1/2021
152	WA	Centralia	3845	BW22		3/2/2021
153	WA	Centralia	3845	BW22		3/3/2021
154	WA	Centralia	3845	BW22		3/4/2021
155	WA	Centralia	3845	BW22		3/5/2021
156	WA	Centralia	3845	BW22		3/6/2021
157	WA	Centralia	3845	BW22		3/7/2021
158	WA	Centralia	3845	BW22		3/8/2021
159	WA	Centralia	3845	BW22		3/9/2021
160	WA	Centralia	3845	BW22		3/10/2021
161	WA	Centralia	3845	BW22		3/11/2021
162	WA	Centralia	3845	BW22		3/12/2021
163	WA	Centralia	3845	BW22		3/13/2021
164	WA	Centralia	3845	BW22		3/14/2021
165	WA	Centralia	3845	BW22		3/15/2021
166	WA	Centralia	3845	BW22		3/16/2021
167	WA	Centralia	3845	BW22		3/17/2021
168	WA	Centralia	3845	BW22		3/18/2021
169	WA	Centralia	3845	BW22		3/19/2021
170	WA	Centralia	3845	BW22		3/20/2021
171	WA	Centralia	3845	BW22		3/21/2021
172	WA	Centralia	3845	BW22		3/22/2021

	A	B	C	D	E	F
173	WA	Centralia	3845	BW22		3/23/2021
174	WA	Centralia	3845	BW22		3/24/2021
175	WA	Centralia	3845	BW22		3/25/2021
176	WA	Centralia	3845	BW22		3/26/2021
177	WA	Centralia	3845	BW22		3/27/2021
178	WA	Centralia	3845	BW22		3/28/2021
179	WA	Centralia	3845	BW22		3/29/2021
180	WA	Centralia	3845	BW22		3/30/2021
181	WA	Centralia	3845	BW22		3/31/2021
182	WA	Centralia	3845	BW22		4/1/2021
183	WA	Centralia	3845	BW22		4/2/2021
184	WA	Centralia	3845	BW22		4/3/2021
185	WA	Centralia	3845	BW22		4/4/2021
186	WA	Centralia	3845	BW22		4/5/2021
187	WA	Centralia	3845	BW22		4/6/2021
188	WA	Centralia	3845	BW22		4/7/2021
189	WA	Centralia	3845	BW22		4/8/2021
190	WA	Centralia	3845	BW22		4/9/2021
191	WA	Centralia	3845	BW22		4/10/2021
192	WA	Centralia	3845	BW22		4/11/2021
193	WA	Centralia	3845	BW22		4/12/2021
194	WA	Centralia	3845	BW22		4/13/2021
195	WA	Centralia	3845	BW22		4/14/2021
196	WA	Centralia	3845	BW22		4/15/2021
197	WA	Centralia	3845	BW22		4/16/2021
198	WA	Centralia	3845	BW22		4/17/2021
199	WA	Centralia	3845	BW22		4/18/2021
200	WA	Centralia	3845	BW22		4/19/2021
201	WA	Centralia	3845	BW22		4/20/2021
202	WA	Centralia	3845	BW22		4/21/2021
203	WA	Centralia	3845	BW22		4/22/2021
204	WA	Centralia	3845	BW22		4/23/2021
205	WA	Centralia	3845	BW22		4/24/2021
206	WA	Centralia	3845	BW22		4/25/2021
207	WA	Centralia	3845	BW22		4/26/2021
208	WA	Centralia	3845	BW22		4/27/2021
209	WA	Centralia	3845	BW22		4/28/2021
210	WA	Centralia	3845	BW22		4/29/2021
211	WA	Centralia	3845	BW22		4/30/2021
212	WA	Centralia	3845	BW22		5/1/2021
213	WA	Centralia	3845	BW22		5/2/2021
214	WA	Centralia	3845	BW22		5/3/2021
215	WA	Centralia	3845	BW22		5/4/2021

	A	B	C	D	E	F
216	WA	Centralia	3845	BW22		5/5/2021
217	WA	Centralia	3845	BW22		5/6/2021
218	WA	Centralia	3845	BW22		5/7/2021
219	WA	Centralia	3845	BW22		5/8/2021
220	WA	Centralia	3845	BW22		5/9/2021
221	WA	Centralia	3845	BW22		5/10/2021
222	WA	Centralia	3845	BW22		5/11/2021
223	WA	Centralia	3845	BW22		5/12/2021
224	WA	Centralia	3845	BW22		5/13/2021
225	WA	Centralia	3845	BW22		5/14/2021
226	WA	Centralia	3845	BW22		5/15/2021
227	WA	Centralia	3845	BW22		5/16/2021
228	WA	Centralia	3845	BW22		5/17/2021
229	WA	Centralia	3845	BW22		5/18/2021
230	WA	Centralia	3845	BW22		5/19/2021
231	WA	Centralia	3845	BW22		5/20/2021
232	WA	Centralia	3845	BW22		5/21/2021
233	WA	Centralia	3845	BW22		5/22/2021
234	WA	Centralia	3845	BW22		5/23/2021
235	WA	Centralia	3845	BW22		5/24/2021
236	WA	Centralia	3845	BW22		5/25/2021
237	WA	Centralia	3845	BW22		5/26/2021
238	WA	Centralia	3845	BW22		5/27/2021
239	WA	Centralia	3845	BW22		5/28/2021
240	WA	Centralia	3845	BW22		5/29/2021
241	WA	Centralia	3845	BW22		5/30/2021
242	WA	Centralia	3845	BW22		5/31/2021
243	WA	Centralia	3845	BW22		6/1/2021
244	WA	Centralia	3845	BW22		6/2/2021
245	WA	Centralia	3845	BW22		6/3/2021
246	WA	Centralia	3845	BW22		6/4/2021
247	WA	Centralia	3845	BW22		6/5/2021
248	WA	Centralia	3845	BW22		6/6/2021
249	WA	Centralia	3845	BW22		6/7/2021
250	WA	Centralia	3845	BW22		6/8/2021
251	WA	Centralia	3845	BW22		6/9/2021
252	WA	Centralia	3845	BW22		6/10/2021
253	WA	Centralia	3845	BW22		6/11/2021
254	WA	Centralia	3845	BW22		6/12/2021
255	WA	Centralia	3845	BW22		6/13/2021
256	WA	Centralia	3845	BW22		6/14/2021
257	WA	Centralia	3845	BW22		6/15/2021
258	WA	Centralia	3845	BW22		6/16/2021

	A	B	C	D	E	F
259	WA	Centralia	3845	BW22		6/17/2021
260	WA	Centralia	3845	BW22		6/18/2021
261	WA	Centralia	3845	BW22		6/19/2021
262	WA	Centralia	3845	BW22		6/20/2021
263	WA	Centralia	3845	BW22		6/21/2021
264	WA	Centralia	3845	BW22		6/22/2021
265	WA	Centralia	3845	BW22		6/23/2021
266	WA	Centralia	3845	BW22		6/24/2021
267	WA	Centralia	3845	BW22		6/25/2021
268	WA	Centralia	3845	BW22		6/26/2021
269	WA	Centralia	3845	BW22		6/27/2021
270	WA	Centralia	3845	BW22		6/28/2021
271	WA	Centralia	3845	BW22		6/29/2021
272	WA	Centralia	3845	BW22		6/30/2021
273	WA	Centralia	3845	BW22		7/1/2021
274	WA	Centralia	3845	BW22		7/2/2021
275	WA	Centralia	3845	BW22		7/3/2021
276	WA	Centralia	3845	BW22		7/4/2021
277	WA	Centralia	3845	BW22		7/5/2021
278	WA	Centralia	3845	BW22		7/6/2021
279	WA	Centralia	3845	BW22		7/7/2021
280	WA	Centralia	3845	BW22		7/8/2021
281	WA	Centralia	3845	BW22		7/9/2021
282	WA	Centralia	3845	BW22		7/10/2021
283	WA	Centralia	3845	BW22		7/11/2021
284	WA	Centralia	3845	BW22		7/12/2021
285	WA	Centralia	3845	BW22		7/13/2021
286	WA	Centralia	3845	BW22		7/14/2021
287	WA	Centralia	3845	BW22		7/15/2021
288	WA	Centralia	3845	BW22		7/16/2021
289	WA	Centralia	3845	BW22		7/17/2021
290	WA	Centralia	3845	BW22		7/18/2021
291	WA	Centralia	3845	BW22		7/19/2021
292	WA	Centralia	3845	BW22		7/20/2021
293	WA	Centralia	3845	BW22		7/21/2021
294	WA	Centralia	3845	BW22		7/22/2021
295	WA	Centralia	3845	BW22		7/23/2021
296	WA	Centralia	3845	BW22		7/24/2021
297	WA	Centralia	3845	BW22		7/25/2021
298	WA	Centralia	3845	BW22		7/26/2021
299	WA	Centralia	3845	BW22		7/27/2021
300	WA	Centralia	3845	BW22		7/28/2021
301	WA	Centralia	3845	BW22		7/29/2021

	A	B	C	D	E	F
302	WA	Centralia	3845	BW22		7/30/2021
303	WA	Centralia	3845	BW22		7/31/2021
304	WA	Centralia	3845	BW22		8/1/2021
305	WA	Centralia	3845	BW22		8/2/2021
306	WA	Centralia	3845	BW22		8/3/2021
307	WA	Centralia	3845	BW22		8/4/2021
308	WA	Centralia	3845	BW22		8/5/2021
309	WA	Centralia	3845	BW22		8/6/2021
310	WA	Centralia	3845	BW22		8/7/2021
311	WA	Centralia	3845	BW22		8/8/2021
312	WA	Centralia	3845	BW22		8/9/2021
313	WA	Centralia	3845	BW22		8/10/2021
314	WA	Centralia	3845	BW22		8/11/2021
315	WA	Centralia	3845	BW22		8/12/2021
316	WA	Centralia	3845	BW22		8/13/2021
317	WA	Centralia	3845	BW22		8/14/2021
318	WA	Centralia	3845	BW22		8/15/2021
319	WA	Centralia	3845	BW22		8/16/2021
320	WA	Centralia	3845	BW22		8/17/2021
321	WA	Centralia	3845	BW22		8/18/2021
322	WA	Centralia	3845	BW22		8/19/2021
323	WA	Centralia	3845	BW22		8/20/2021
324	WA	Centralia	3845	BW22		8/21/2021
325	WA	Centralia	3845	BW22		8/22/2021
326	WA	Centralia	3845	BW22		8/23/2021
327	WA	Centralia	3845	BW22		8/24/2021
328	WA	Centralia	3845	BW22		8/25/2021
329	WA	Centralia	3845	BW22		8/26/2021
330	WA	Centralia	3845	BW22		8/27/2021
331	WA	Centralia	3845	BW22		8/28/2021
332	WA	Centralia	3845	BW22		8/29/2021
333	WA	Centralia	3845	BW22		8/30/2021
334	WA	Centralia	3845	BW22		8/31/2021
335	WA	Centralia	3845	BW22		9/1/2021
336	WA	Centralia	3845	BW22		9/2/2021
337	WA	Centralia	3845	BW22		9/3/2021
338	WA	Centralia	3845	BW22		9/4/2021
339	WA	Centralia	3845	BW22		9/5/2021
340	WA	Centralia	3845	BW22		9/6/2021
341	WA	Centralia	3845	BW22		9/7/2021
342	WA	Centralia	3845	BW22		9/8/2021
343	WA	Centralia	3845	BW22		9/9/2021
344	WA	Centralia	3845	BW22		9/10/2021

	A	B	C	D	E	F
345	WA	Centralia	3845	BW22		9/11/2021
346	WA	Centralia	3845	BW22		9/12/2021
347	WA	Centralia	3845	BW22		9/13/2021
348	WA	Centralia	3845	BW22		9/14/2021
349	WA	Centralia	3845	BW22		9/15/2021
350	WA	Centralia	3845	BW22		9/16/2021
351	WA	Centralia	3845	BW22		9/17/2021
352	WA	Centralia	3845	BW22		9/18/2021
353	WA	Centralia	3845	BW22		9/19/2021
354	WA	Centralia	3845	BW22		9/20/2021
355	WA	Centralia	3845	BW22		9/21/2021
356	WA	Centralia	3845	BW22		9/22/2021
357	WA	Centralia	3845	BW22		9/23/2021
358	WA	Centralia	3845	BW22		9/24/2021
359	WA	Centralia	3845	BW22		9/25/2021
360	WA	Centralia	3845	BW22		9/26/2021
361	WA	Centralia	3845	BW22		9/27/2021
362	WA	Centralia	3845	BW22		9/28/2021
363	WA	Centralia	3845	BW22		9/29/2021
364	WA	Centralia	3845	BW22		9/30/2021
365	WA	Centralia	3845	BW22		10/1/2021
366	WA	Centralia	3845	BW22		10/2/2021
367	WA	Centralia	3845	BW22		10/3/2021
368	WA	Centralia	3845	BW22		10/4/2021
369	WA	Centralia	3845	BW22		10/5/2021
370	WA	Centralia	3845	BW22		10/6/2021
371	WA	Centralia	3845	BW22		10/7/2021
372	WA	Centralia	3845	BW22		10/8/2021
373	WA	Centralia	3845	BW22		10/9/2021
374	WA	Centralia	3845	BW22		10/10/2021
375	WA	Centralia	3845	BW22		10/11/2021
376	WA	Centralia	3845	BW22		10/12/2021
377	WA	Centralia	3845	BW22		10/13/2021
378	WA	Centralia	3845	BW22		10/14/2021
379	WA	Centralia	3845	BW22		10/15/2021
380	WA	Centralia	3845	BW22		10/16/2021
381	WA	Centralia	3845	BW22		10/17/2021
382	WA	Centralia	3845	BW22		10/18/2021
383	WA	Centralia	3845	BW22		10/19/2021
384	WA	Centralia	3845	BW22		10/20/2021
385	WA	Centralia	3845	BW22		10/21/2021
386	WA	Centralia	3845	BW22		10/22/2021
387	WA	Centralia	3845	BW22		10/23/2021

	A	B	C	D	E	F
388	WA	Centralia	3845	BW22		10/24/2021
389	WA	Centralia	3845	BW22		10/25/2021
390	WA	Centralia	3845	BW22		10/26/2021
391	WA	Centralia	3845	BW22		10/27/2021
392	WA	Centralia	3845	BW22		10/28/2021
393	WA	Centralia	3845	BW22		10/29/2021
394	WA	Centralia	3845	BW22		10/30/2021
395	WA	Centralia	3845	BW22		10/31/2021
396	WA	Centralia	3845	BW22		11/1/2021
397	WA	Centralia	3845	BW22		11/2/2021
398	WA	Centralia	3845	BW22		11/3/2021
399	WA	Centralia	3845	BW22		11/4/2021
400	WA	Centralia	3845	BW22		11/5/2021
401	WA	Centralia	3845	BW22		11/6/2021
402	WA	Centralia	3845	BW22		11/7/2021
403	WA	Centralia	3845	BW22		11/8/2021
404	WA	Centralia	3845	BW22		11/9/2021
405	WA	Centralia	3845	BW22		11/10/2021
406	WA	Centralia	3845	BW22		11/11/2021
407	WA	Centralia	3845	BW22		11/12/2021
408	WA	Centralia	3845	BW22		11/13/2021
409	WA	Centralia	3845	BW22		11/14/2021
410	WA	Centralia	3845	BW22		11/15/2021
411	WA	Centralia	3845	BW22		11/16/2021
412	WA	Centralia	3845	BW22		11/17/2021
413	WA	Centralia	3845	BW22		11/18/2021
414	WA	Centralia	3845	BW22		11/19/2021
415	WA	Centralia	3845	BW22		11/20/2021
416	WA	Centralia	3845	BW22		11/21/2021
417	WA	Centralia	3845	BW22		11/22/2021
418	WA	Centralia	3845	BW22		11/23/2021
419	WA	Centralia	3845	BW22		11/24/2021
420	WA	Centralia	3845	BW22		11/25/2021
421	WA	Centralia	3845	BW22		11/26/2021
422	WA	Centralia	3845	BW22		11/27/2021
423	WA	Centralia	3845	BW22		11/28/2021
424	WA	Centralia	3845	BW22		11/29/2021
425	WA	Centralia	3845	BW22		11/30/2021
426	WA	Centralia	3845	BW22		12/1/2021
427	WA	Centralia	3845	BW22		12/2/2021
428	WA	Centralia	3845	BW22		12/3/2021
429	WA	Centralia	3845	BW22		12/4/2021
430	WA	Centralia	3845	BW22		12/5/2021

	A	B	C	D	E	F
431	WA	Centralia	3845	BW22		12/6/2021
432	WA	Centralia	3845	BW22		12/7/2021
433	WA	Centralia	3845	BW22		12/8/2021
434	WA	Centralia	3845	BW22		12/9/2021
435	WA	Centralia	3845	BW22		12/10/2021
436	WA	Centralia	3845	BW22		12/11/2021
437	WA	Centralia	3845	BW22		12/12/2021
438	WA	Centralia	3845	BW22		12/13/2021
439	WA	Centralia	3845	BW22		12/14/2021
440	WA	Centralia	3845	BW22		12/15/2021
441	WA	Centralia	3845	BW22		12/16/2021
442	WA	Centralia	3845	BW22		12/17/2021
443	WA	Centralia	3845	BW22		12/18/2021
444	WA	Centralia	3845	BW22		12/19/2021
445	WA	Centralia	3845	BW22		12/20/2021
446	WA	Centralia	3845	BW22		12/21/2021
447	WA	Centralia	3845	BW22		12/22/2021
448	WA	Centralia	3845	BW22		12/23/2021
449	WA	Centralia	3845	BW22		12/24/2021
450	WA	Centralia	3845	BW22		12/25/2021
451	WA	Centralia	3845	BW22		12/26/2021
452	WA	Centralia	3845	BW22		12/27/2021
453	WA	Centralia	3845	BW22		12/28/2021
454	WA	Centralia	3845	BW22		12/29/2021
455	WA	Centralia	3845	BW22		12/30/2021
456	WA	Centralia	3845	BW22		12/31/2021
457	WA	Centralia	3845	BW22		1/1/2022
458	WA	Centralia	3845	BW22		1/2/2022
459	WA	Centralia	3845	BW22		1/3/2022
460	WA	Centralia	3845	BW22		1/4/2022
461	WA	Centralia	3845	BW22		1/5/2022
462	WA	Centralia	3845	BW22		1/6/2022
463	WA	Centralia	3845	BW22		1/7/2022
464	WA	Centralia	3845	BW22		1/8/2022
465	WA	Centralia	3845	BW22		1/9/2022
466	WA	Centralia	3845	BW22		1/10/2022
467	WA	Centralia	3845	BW22		1/11/2022
468	WA	Centralia	3845	BW22		1/12/2022
469	WA	Centralia	3845	BW22		1/13/2022
470	WA	Centralia	3845	BW22		1/14/2022
471	WA	Centralia	3845	BW22		1/15/2022
472	WA	Centralia	3845	BW22		1/16/2022
473	WA	Centralia	3845	BW22		1/17/2022

	A	B	C	D	E	F
474	WA	Centralia	3845	BW22		1/18/2022
475	WA	Centralia	3845	BW22		1/19/2022
476	WA	Centralia	3845	BW22		1/20/2022
477	WA	Centralia	3845	BW22		1/21/2022
478	WA	Centralia	3845	BW22		1/22/2022
479	WA	Centralia	3845	BW22		1/23/2022
480	WA	Centralia	3845	BW22		1/24/2022
481	WA	Centralia	3845	BW22		1/25/2022
482	WA	Centralia	3845	BW22		1/26/2022
483	WA	Centralia	3845	BW22		1/27/2022
484	WA	Centralia	3845	BW22		1/28/2022
485	WA	Centralia	3845	BW22		1/29/2022
486	WA	Centralia	3845	BW22		1/30/2022
487	WA	Centralia	3845	BW22		1/31/2022
488	WA	Centralia	3845	BW22		2/1/2022
489	WA	Centralia	3845	BW22		2/2/2022
490	WA	Centralia	3845	BW22		2/3/2022
491	WA	Centralia	3845	BW22		2/4/2022
492	WA	Centralia	3845	BW22		2/5/2022
493	WA	Centralia	3845	BW22		2/6/2022
494	WA	Centralia	3845	BW22		2/7/2022
495	WA	Centralia	3845	BW22		2/8/2022
496	WA	Centralia	3845	BW22		2/9/2022
497	WA	Centralia	3845	BW22		2/10/2022
498	WA	Centralia	3845	BW22		2/11/2022
499	WA	Centralia	3845	BW22		2/12/2022
500	WA	Centralia	3845	BW22		2/13/2022
501	WA	Centralia	3845	BW22		2/14/2022
502	WA	Centralia	3845	BW22		2/15/2022
503	WA	Centralia	3845	BW22		2/16/2022
504	WA	Centralia	3845	BW22		2/17/2022
505	WA	Centralia	3845	BW22		2/18/2022
506	WA	Centralia	3845	BW22		2/19/2022
507	WA	Centralia	3845	BW22		2/20/2022
508	WA	Centralia	3845	BW22		2/21/2022
509	WA	Centralia	3845	BW22		2/22/2022
510	WA	Centralia	3845	BW22		2/23/2022
511	WA	Centralia	3845	BW22		2/24/2022
512	WA	Centralia	3845	BW22		2/25/2022
513	WA	Centralia	3845	BW22		2/26/2022
514	WA	Centralia	3845	BW22		2/27/2022
515	WA	Centralia	3845	BW22		2/28/2022
516	WA	Centralia	3845	BW22		3/1/2022

	A	B	C	D	E	F
517	WA	Centralia	3845	BW22		3/2/2022
518	WA	Centralia	3845	BW22		3/3/2022
519	WA	Centralia	3845	BW22		3/4/2022
520	WA	Centralia	3845	BW22		3/5/2022
521	WA	Centralia	3845	BW22		3/6/2022
522	WA	Centralia	3845	BW22		3/7/2022
523	WA	Centralia	3845	BW22		3/8/2022
524	WA	Centralia	3845	BW22		3/9/2022
525	WA	Centralia	3845	BW22		3/10/2022
526	WA	Centralia	3845	BW22		3/11/2022
527	WA	Centralia	3845	BW22		3/12/2022
528	WA	Centralia	3845	BW22		3/13/2022
529	WA	Centralia	3845	BW22		3/14/2022
530	WA	Centralia	3845	BW22		3/15/2022
531	WA	Centralia	3845	BW22		3/16/2022
532	WA	Centralia	3845	BW22		3/17/2022
533	WA	Centralia	3845	BW22		3/18/2022
534	WA	Centralia	3845	BW22		3/19/2022
535	WA	Centralia	3845	BW22		3/20/2022
536	WA	Centralia	3845	BW22		3/21/2022
537	WA	Centralia	3845	BW22		3/22/2022
538	WA	Centralia	3845	BW22		3/23/2022
539	WA	Centralia	3845	BW22		3/24/2022
540	WA	Centralia	3845	BW22		3/25/2022
541	WA	Centralia	3845	BW22		3/26/2022
542	WA	Centralia	3845	BW22		3/27/2022
543	WA	Centralia	3845	BW22		3/28/2022
544	WA	Centralia	3845	BW22		3/29/2022
545	WA	Centralia	3845	BW22		3/30/2022
546	WA	Centralia	3845	BW22		3/31/2022
547	WA	Centralia	3845	BW22		4/1/2022
548	WA	Centralia	3845	BW22		4/2/2022
549	WA	Centralia	3845	BW22		4/3/2022
550	WA	Centralia	3845	BW22		4/4/2022
551	WA	Centralia	3845	BW22		4/5/2022
552	WA	Centralia	3845	BW22		4/6/2022
553	WA	Centralia	3845	BW22		4/7/2022
554	WA	Centralia	3845	BW22		4/8/2022
555	WA	Centralia	3845	BW22		4/9/2022
556	WA	Centralia	3845	BW22		4/10/2022
557	WA	Centralia	3845	BW22		4/11/2022
558	WA	Centralia	3845	BW22		4/12/2022
559	WA	Centralia	3845	BW22		4/13/2022

	A	B	C	D	E	F
560	WA	Centralia	3845	BW22		4/14/2022
561	WA	Centralia	3845	BW22		4/15/2022
562	WA	Centralia	3845	BW22		4/16/2022
563	WA	Centralia	3845	BW22		4/17/2022
564	WA	Centralia	3845	BW22		4/18/2022
565	WA	Centralia	3845	BW22		4/19/2022
566	WA	Centralia	3845	BW22		4/20/2022
567	WA	Centralia	3845	BW22		4/21/2022
568	WA	Centralia	3845	BW22		4/22/2022
569	WA	Centralia	3845	BW22		4/23/2022
570	WA	Centralia	3845	BW22		4/24/2022
571	WA	Centralia	3845	BW22		4/25/2022
572	WA	Centralia	3845	BW22		4/26/2022
573	WA	Centralia	3845	BW22		4/27/2022
574	WA	Centralia	3845	BW22		4/28/2022
575	WA	Centralia	3845	BW22		4/29/2022
576	WA	Centralia	3845	BW22		4/30/2022
577	WA	Centralia	3845	BW22		5/1/2022
578	WA	Centralia	3845	BW22		5/2/2022
579	WA	Centralia	3845	BW22		5/3/2022
580	WA	Centralia	3845	BW22		5/4/2022
581	WA	Centralia	3845	BW22		5/5/2022
582	WA	Centralia	3845	BW22		5/6/2022
583	WA	Centralia	3845	BW22		5/7/2022
584	WA	Centralia	3845	BW22		5/8/2022
585	WA	Centralia	3845	BW22		5/9/2022
586	WA	Centralia	3845	BW22		5/10/2022
587	WA	Centralia	3845	BW22		5/11/2022
588	WA	Centralia	3845	BW22		5/12/2022
589	WA	Centralia	3845	BW22		5/13/2022
590	WA	Centralia	3845	BW22		5/14/2022
591	WA	Centralia	3845	BW22		5/15/2022
592	WA	Centralia	3845	BW22		5/16/2022
593	WA	Centralia	3845	BW22		5/17/2022
594	WA	Centralia	3845	BW22		5/18/2022
595	WA	Centralia	3845	BW22		5/19/2022
596	WA	Centralia	3845	BW22		5/20/2022
597	WA	Centralia	3845	BW22		5/21/2022
598	WA	Centralia	3845	BW22		5/22/2022
599	WA	Centralia	3845	BW22		5/23/2022
600	WA	Centralia	3845	BW22		5/24/2022
601	WA	Centralia	3845	BW22		5/25/2022
602	WA	Centralia	3845	BW22		5/26/2022

	A	B	C	D	E	F
603	WA	Centralia	3845	BW22		5/27/2022
604	WA	Centralia	3845	BW22		5/28/2022
605	WA	Centralia	3845	BW22		5/29/2022
606	WA	Centralia	3845	BW22		5/30/2022
607	WA	Centralia	3845	BW22		5/31/2022
608	WA	Centralia	3845	BW22		6/1/2022
609	WA	Centralia	3845	BW22		6/2/2022
610	WA	Centralia	3845	BW22		6/3/2022
611	WA	Centralia	3845	BW22		6/4/2022
612	WA	Centralia	3845	BW22		6/5/2022
613	WA	Centralia	3845	BW22		6/6/2022
614	WA	Centralia	3845	BW22		6/7/2022
615	WA	Centralia	3845	BW22		6/8/2022
616	WA	Centralia	3845	BW22		6/9/2022
617	WA	Centralia	3845	BW22		6/10/2022
618	WA	Centralia	3845	BW22		6/11/2022
619	WA	Centralia	3845	BW22		6/12/2022
620	WA	Centralia	3845	BW22		6/13/2022
621	WA	Centralia	3845	BW22		6/14/2022
622	WA	Centralia	3845	BW22		6/15/2022
623	WA	Centralia	3845	BW22		6/16/2022
624	WA	Centralia	3845	BW22		6/17/2022
625	WA	Centralia	3845	BW22		6/18/2022
626	WA	Centralia	3845	BW22		6/19/2022
627	WA	Centralia	3845	BW22		6/20/2022
628	WA	Centralia	3845	BW22		6/21/2022
629	WA	Centralia	3845	BW22		6/22/2022
630	WA	Centralia	3845	BW22		6/23/2022
631	WA	Centralia	3845	BW22		6/24/2022
632	WA	Centralia	3845	BW22		6/25/2022
633	WA	Centralia	3845	BW22		6/26/2022
634	WA	Centralia	3845	BW22		6/27/2022
635	WA	Centralia	3845	BW22		6/28/2022
636	WA	Centralia	3845	BW22		6/29/2022
637	WA	Centralia	3845	BW22		6/30/2022
638	WA	Centralia	3845	BW22		7/1/2022
639	WA	Centralia	3845	BW22		7/2/2022
640	WA	Centralia	3845	BW22		7/3/2022
641	WA	Centralia	3845	BW22		7/4/2022
642	WA	Centralia	3845	BW22		7/5/2022
643	WA	Centralia	3845	BW22		7/6/2022
644	WA	Centralia	3845	BW22		7/7/2022
645	WA	Centralia	3845	BW22		7/8/2022

	A	B	C	D	E	F
646	WA	Centralia	3845	BW22		7/9/2022
647	WA	Centralia	3845	BW22		7/10/2022
648	WA	Centralia	3845	BW22		7/11/2022
649	WA	Centralia	3845	BW22		7/12/2022
650	WA	Centralia	3845	BW22		7/13/2022
651	WA	Centralia	3845	BW22		7/14/2022
652	WA	Centralia	3845	BW22		7/15/2022
653	WA	Centralia	3845	BW22		7/16/2022
654	WA	Centralia	3845	BW22		7/17/2022
655	WA	Centralia	3845	BW22		7/18/2022
656	WA	Centralia	3845	BW22		7/19/2022
657	WA	Centralia	3845	BW22		7/20/2022
658	WA	Centralia	3845	BW22		7/21/2022
659	WA	Centralia	3845	BW22		7/22/2022
660	WA	Centralia	3845	BW22		7/23/2022
661	WA	Centralia	3845	BW22		7/24/2022
662	WA	Centralia	3845	BW22		7/25/2022
663	WA	Centralia	3845	BW22		7/26/2022
664	WA	Centralia	3845	BW22		7/27/2022
665	WA	Centralia	3845	BW22		7/28/2022
666	WA	Centralia	3845	BW22		7/29/2022
667	WA	Centralia	3845	BW22		7/30/2022
668	WA	Centralia	3845	BW22		7/31/2022
669	WA	Centralia	3845	BW22		8/1/2022
670	WA	Centralia	3845	BW22		8/2/2022
671	WA	Centralia	3845	BW22		8/3/2022
672	WA	Centralia	3845	BW22		8/4/2022
673	WA	Centralia	3845	BW22		8/5/2022
674	WA	Centralia	3845	BW22		8/6/2022
675	WA	Centralia	3845	BW22		8/7/2022
676	WA	Centralia	3845	BW22		8/8/2022
677	WA	Centralia	3845	BW22		8/9/2022
678	WA	Centralia	3845	BW22		8/10/2022
679	WA	Centralia	3845	BW22		8/11/2022
680	WA	Centralia	3845	BW22		8/12/2022
681	WA	Centralia	3845	BW22		8/13/2022
682	WA	Centralia	3845	BW22		8/14/2022
683	WA	Centralia	3845	BW22		8/15/2022
684	WA	Centralia	3845	BW22		8/16/2022
685	WA	Centralia	3845	BW22		8/17/2022
686	WA	Centralia	3845	BW22		8/18/2022
687	WA	Centralia	3845	BW22		8/19/2022
688	WA	Centralia	3845	BW22		8/20/2022

	A	B	C	D	E	F
689	WA	Centralia	3845	BW22		8/21/2022
690	WA	Centralia	3845	BW22		8/22/2022
691	WA	Centralia	3845	BW22		8/23/2022
692	WA	Centralia	3845	BW22		8/24/2022
693	WA	Centralia	3845	BW22		8/25/2022
694	WA	Centralia	3845	BW22		8/26/2022
695	WA	Centralia	3845	BW22		8/27/2022
696	WA	Centralia	3845	BW22		8/28/2022
697	WA	Centralia	3845	BW22		8/29/2022
698	WA	Centralia	3845	BW22		8/30/2022
699	WA	Centralia	3845	BW22		8/31/2022
700	WA	Centralia	3845	BW22		9/1/2022
701	WA	Centralia	3845	BW22		9/2/2022
702	WA	Centralia	3845	BW22		9/3/2022
703	WA	Centralia	3845	BW22		9/4/2022
704	WA	Centralia	3845	BW22		9/5/2022
705	WA	Centralia	3845	BW22		9/6/2022
706	WA	Centralia	3845	BW22		9/7/2022
707	WA	Centralia	3845	BW22		9/8/2022
708	WA	Centralia	3845	BW22		9/9/2022
709	WA	Centralia	3845	BW22		9/10/2022
710	WA	Centralia	3845	BW22		9/11/2022
711	WA	Centralia	3845	BW22		9/12/2022
712	WA	Centralia	3845	BW22		9/13/2022
713	WA	Centralia	3845	BW22		9/14/2022
714	WA	Centralia	3845	BW22		9/15/2022
715	WA	Centralia	3845	BW22		9/16/2022
716	WA	Centralia	3845	BW22		9/17/2022
717	WA	Centralia	3845	BW22		9/18/2022
718	WA	Centralia	3845	BW22		9/19/2022
719	WA	Centralia	3845	BW22		9/20/2022
720	WA	Centralia	3845	BW22		9/21/2022
721	WA	Centralia	3845	BW22		9/22/2022
722	WA	Centralia	3845	BW22		9/23/2022
723	WA	Centralia	3845	BW22		9/24/2022
724	WA	Centralia	3845	BW22		9/25/2022
725	WA	Centralia	3845	BW22		9/26/2022
726	WA	Centralia	3845	BW22		9/27/2022
727	WA	Centralia	3845	BW22		9/28/2022
728	WA	Centralia	3845	BW22		9/29/2022
729	WA	Centralia	3845	BW22		9/30/2022
730	WA	Centralia	3845	BW22		10/1/2022
731	WA	Centralia	3845	BW22		10/2/2022

	A	B	C	D	E	F
732	WA	Centralia	3845	BW22		10/3/2022
733	WA	Centralia	3845	BW22		10/4/2022
734	WA	Centralia	3845	BW22		10/5/2022
735	WA	Centralia	3845	BW22		10/6/2022
736	WA	Centralia	3845	BW22		10/7/2022
737	WA	Centralia	3845	BW22		10/8/2022
738	WA	Centralia	3845	BW22		10/9/2022
739	WA	Centralia	3845	BW22		10/10/2022
740	WA	Centralia	3845	BW22		10/11/2022
741	WA	Centralia	3845	BW22		10/12/2022
742	WA	Centralia	3845	BW22		10/13/2022
743	WA	Centralia	3845	BW22		10/14/2022
744	WA	Centralia	3845	BW22		10/15/2022
745	WA	Centralia	3845	BW22		10/16/2022
746	WA	Centralia	3845	BW22		10/17/2022
747	WA	Centralia	3845	BW22		10/18/2022
748	WA	Centralia	3845	BW22		10/19/2022
749	WA	Centralia	3845	BW22		10/20/2022
750	WA	Centralia	3845	BW22		10/21/2022
751	WA	Centralia	3845	BW22		10/22/2022
752	WA	Centralia	3845	BW22		10/23/2022
753	WA	Centralia	3845	BW22		10/24/2022
754	WA	Centralia	3845	BW22		10/25/2022
755	WA	Centralia	3845	BW22		10/26/2022
756	WA	Centralia	3845	BW22		10/27/2022
757	WA	Centralia	3845	BW22		10/28/2022
758	WA	Centralia	3845	BW22		10/29/2022
759	WA	Centralia	3845	BW22		10/30/2022
760	WA	Centralia	3845	BW22		10/31/2022
761	WA	Centralia	3845	BW22		11/1/2022
762	WA	Centralia	3845	BW22		11/2/2022
763	WA	Centralia	3845	BW22		11/3/2022
764	WA	Centralia	3845	BW22		11/4/2022
765	WA	Centralia	3845	BW22		11/5/2022
766	WA	Centralia	3845	BW22		11/6/2022
767	WA	Centralia	3845	BW22		11/7/2022
768	WA	Centralia	3845	BW22		11/8/2022
769	WA	Centralia	3845	BW22		11/9/2022
770	WA	Centralia	3845	BW22		11/10/2022
771	WA	Centralia	3845	BW22		11/11/2022
772	WA	Centralia	3845	BW22		11/12/2022
773	WA	Centralia	3845	BW22		11/13/2022
774	WA	Centralia	3845	BW22		11/14/2022

	A	B	C	D	E	F
775	WA	Centralia	3845	BW22		11/15/2022
776	WA	Centralia	3845	BW22		11/16/2022
777	WA	Centralia	3845	BW22		11/17/2022
778	WA	Centralia	3845	BW22		11/18/2022
779	WA	Centralia	3845	BW22		11/19/2022
780	WA	Centralia	3845	BW22		11/20/2022
781	WA	Centralia	3845	BW22		11/21/2022
782	WA	Centralia	3845	BW22		11/22/2022
783	WA	Centralia	3845	BW22		11/23/2022
784	WA	Centralia	3845	BW22		11/24/2022
785	WA	Centralia	3845	BW22		11/25/2022
786	WA	Centralia	3845	BW22		11/26/2022
787	WA	Centralia	3845	BW22		11/27/2022
788	WA	Centralia	3845	BW22		11/28/2022
789	WA	Centralia	3845	BW22		11/29/2022
790	WA	Centralia	3845	BW22		11/30/2022
791	WA	Centralia	3845	BW22		12/1/2022
792	WA	Centralia	3845	BW22		12/2/2022
793	WA	Centralia	3845	BW22		12/3/2022
794	WA	Centralia	3845	BW22		12/4/2022
795	WA	Centralia	3845	BW22		12/5/2022
796	WA	Centralia	3845	BW22		12/6/2022
797	WA	Centralia	3845	BW22		12/7/2022
798	WA	Centralia	3845	BW22		12/8/2022
799	WA	Centralia	3845	BW22		12/9/2022
800	WA	Centralia	3845	BW22		12/10/2022
801	WA	Centralia	3845	BW22		12/11/2022
802	WA	Centralia	3845	BW22		12/12/2022
803	WA	Centralia	3845	BW22		12/13/2022
804	WA	Centralia	3845	BW22		12/14/2022
805	WA	Centralia	3845	BW22		12/15/2022
806	WA	Centralia	3845	BW22		12/16/2022
807	WA	Centralia	3845	BW22		12/17/2022
808	WA	Centralia	3845	BW22		12/18/2022
809	WA	Centralia	3845	BW22		12/19/2022
810	WA	Centralia	3845	BW22		12/20/2022
811	WA	Centralia	3845	BW22		12/21/2022
812	WA	Centralia	3845	BW22		12/22/2022
813	WA	Centralia	3845	BW22		12/23/2022
814	WA	Centralia	3845	BW22		12/24/2022
815	WA	Centralia	3845	BW22		12/25/2022
816	WA	Centralia	3845	BW22		12/26/2022
817	WA	Centralia	3845	BW22		12/27/2022

	A	B	C	D	E	F
818	WA	Centralia	3845	BW22		12/28/2022
819	WA	Centralia	3845	BW22		12/29/2022
820	WA	Centralia	3845	BW22		12/30/2022
821	WA	Centralia	3845	BW22		12/31/2022
822	WA	Centralia	3845	BW22		1/1/2023
823	WA	Centralia	3845	BW22		1/2/2023
824	WA	Centralia	3845	BW22		1/3/2023
825	WA	Centralia	3845	BW22		1/4/2023
826	WA	Centralia	3845	BW22		1/5/2023
827	WA	Centralia	3845	BW22		1/6/2023
828	WA	Centralia	3845	BW22		1/7/2023
829	WA	Centralia	3845	BW22		1/8/2023
830	WA	Centralia	3845	BW22		1/9/2023
831	WA	Centralia	3845	BW22		1/10/2023
832	WA	Centralia	3845	BW22		1/11/2023
833	WA	Centralia	3845	BW22		1/12/2023
834	WA	Centralia	3845	BW22		1/13/2023
835	WA	Centralia	3845	BW22		1/14/2023
836	WA	Centralia	3845	BW22		1/15/2023
837	WA	Centralia	3845	BW22		1/16/2023
838	WA	Centralia	3845	BW22		1/17/2023
839	WA	Centralia	3845	BW22		1/18/2023
840	WA	Centralia	3845	BW22		1/19/2023
841	WA	Centralia	3845	BW22		1/20/2023
842	WA	Centralia	3845	BW22		1/21/2023
843	WA	Centralia	3845	BW22		1/22/2023
844	WA	Centralia	3845	BW22		1/23/2023
845	WA	Centralia	3845	BW22		1/24/2023
846	WA	Centralia	3845	BW22		1/25/2023
847	WA	Centralia	3845	BW22		1/26/2023
848	WA	Centralia	3845	BW22		1/27/2023
849	WA	Centralia	3845	BW22		1/28/2023
850	WA	Centralia	3845	BW22		1/29/2023
851	WA	Centralia	3845	BW22		1/30/2023
852	WA	Centralia	3845	BW22		1/31/2023
853	WA	Centralia	3845	BW22		2/1/2023
854	WA	Centralia	3845	BW22		2/2/2023
855	WA	Centralia	3845	BW22		2/3/2023
856	WA	Centralia	3845	BW22		2/4/2023
857	WA	Centralia	3845	BW22		2/5/2023
858	WA	Centralia	3845	BW22		2/6/2023
859	WA	Centralia	3845	BW22		2/7/2023
860	WA	Centralia	3845	BW22		2/8/2023

	A	B	C	D	E	F
861	WA	Centralia	3845	BW22		2/9/2023
862	WA	Centralia	3845	BW22		2/10/2023
863	WA	Centralia	3845	BW22		2/11/2023
864	WA	Centralia	3845	BW22		2/12/2023
865	WA	Centralia	3845	BW22		2/13/2023
866	WA	Centralia	3845	BW22		2/14/2023
867	WA	Centralia	3845	BW22		2/15/2023
868	WA	Centralia	3845	BW22		2/16/2023
869	WA	Centralia	3845	BW22		2/17/2023
870	WA	Centralia	3845	BW22		2/18/2023
871	WA	Centralia	3845	BW22		2/19/2023
872	WA	Centralia	3845	BW22		2/20/2023
873	WA	Centralia	3845	BW22		2/21/2023
874	WA	Centralia	3845	BW22		2/22/2023
875	WA	Centralia	3845	BW22		2/23/2023
876	WA	Centralia	3845	BW22		2/24/2023
877	WA	Centralia	3845	BW22		2/25/2023
878	WA	Centralia	3845	BW22		2/26/2023
879	WA	Centralia	3845	BW22		2/27/2023
880	WA	Centralia	3845	BW22		2/28/2023
881	WA	Centralia	3845	BW22		3/1/2023
882	WA	Centralia	3845	BW22		3/2/2023
883	WA	Centralia	3845	BW22		3/3/2023
884	WA	Centralia	3845	BW22		3/4/2023
885	WA	Centralia	3845	BW22		3/5/2023
886	WA	Centralia	3845	BW22		3/6/2023
887	WA	Centralia	3845	BW22		3/7/2023
888	WA	Centralia	3845	BW22		3/8/2023
889	WA	Centralia	3845	BW22		3/9/2023
890	WA	Centralia	3845	BW22		3/10/2023
891	WA	Centralia	3845	BW22		3/11/2023
892	WA	Centralia	3845	BW22		3/12/2023
893	WA	Centralia	3845	BW22		3/13/2023
894	WA	Centralia	3845	BW22		3/14/2023
895	WA	Centralia	3845	BW22		3/15/2023
896	WA	Centralia	3845	BW22		3/16/2023
897	WA	Centralia	3845	BW22		3/17/2023
898	WA	Centralia	3845	BW22		3/18/2023
899	WA	Centralia	3845	BW22		3/19/2023
900	WA	Centralia	3845	BW22		3/20/2023
901	WA	Centralia	3845	BW22		3/21/2023
902	WA	Centralia	3845	BW22		3/22/2023
903	WA	Centralia	3845	BW22		3/23/2023

	A	B	C	D	E	F
904	WA	Centralia	3845	BW22		3/24/2023
905	WA	Centralia	3845	BW22		3/25/2023
906	WA	Centralia	3845	BW22		3/26/2023
907	WA	Centralia	3845	BW22		3/27/2023
908	WA	Centralia	3845	BW22		3/28/2023
909	WA	Centralia	3845	BW22		3/29/2023
910	WA	Centralia	3845	BW22		3/30/2023
911	WA	Centralia	3845	BW22		3/31/2023
912	WA	Centralia	3845	BW22		4/1/2023
913	WA	Centralia	3845	BW22		4/2/2023
914	WA	Centralia	3845	BW22		4/3/2023
915	WA	Centralia	3845	BW22		4/4/2023
916	WA	Centralia	3845	BW22		4/5/2023
917	WA	Centralia	3845	BW22		4/6/2023
918	WA	Centralia	3845	BW22		4/7/2023
919	WA	Centralia	3845	BW22		4/8/2023
920	WA	Centralia	3845	BW22		4/9/2023
921	WA	Centralia	3845	BW22		4/10/2023
922	WA	Centralia	3845	BW22		4/11/2023
923	WA	Centralia	3845	BW22		4/12/2023
924	WA	Centralia	3845	BW22		4/13/2023
925	WA	Centralia	3845	BW22		4/14/2023
926	WA	Centralia	3845	BW22		4/15/2023
927	WA	Centralia	3845	BW22		4/16/2023
928	WA	Centralia	3845	BW22		4/17/2023
929	WA	Centralia	3845	BW22		4/18/2023
930	WA	Centralia	3845	BW22		4/19/2023
931	WA	Centralia	3845	BW22		4/20/2023
932	WA	Centralia	3845	BW22		4/21/2023
933	WA	Centralia	3845	BW22		4/22/2023
934	WA	Centralia	3845	BW22		4/23/2023
935	WA	Centralia	3845	BW22		4/24/2023
936	WA	Centralia	3845	BW22		4/25/2023
937	WA	Centralia	3845	BW22		4/26/2023
938	WA	Centralia	3845	BW22		4/27/2023
939	WA	Centralia	3845	BW22		4/28/2023
940	WA	Centralia	3845	BW22		4/29/2023
941	WA	Centralia	3845	BW22		4/30/2023
942	WA	Centralia	3845	BW22		5/1/2023
943	WA	Centralia	3845	BW22		5/2/2023
944	WA	Centralia	3845	BW22		5/3/2023
945	WA	Centralia	3845	BW22		5/4/2023
946	WA	Centralia	3845	BW22		5/5/2023

	A	B	C	D	E	F
947	WA	Centralia	3845	BW22		5/6/2023
948	WA	Centralia	3845	BW22		5/7/2023
949	WA	Centralia	3845	BW22		5/8/2023
950	WA	Centralia	3845	BW22		5/9/2023
951	WA	Centralia	3845	BW22		5/10/2023
952	WA	Centralia	3845	BW22		5/11/2023
953	WA	Centralia	3845	BW22		5/12/2023
954	WA	Centralia	3845	BW22		5/13/2023
955	WA	Centralia	3845	BW22		5/14/2023
956	WA	Centralia	3845	BW22		5/15/2023
957	WA	Centralia	3845	BW22		5/16/2023
958	WA	Centralia	3845	BW22		5/17/2023
959	WA	Centralia	3845	BW22		5/18/2023
960	WA	Centralia	3845	BW22		5/19/2023
961	WA	Centralia	3845	BW22		5/20/2023
962	WA	Centralia	3845	BW22		5/21/2023
963	WA	Centralia	3845	BW22		5/22/2023
964	WA	Centralia	3845	BW22		5/23/2023
965	WA	Centralia	3845	BW22		5/24/2023
966	WA	Centralia	3845	BW22		5/25/2023
967	WA	Centralia	3845	BW22		5/26/2023
968	WA	Centralia	3845	BW22		5/27/2023
969	WA	Centralia	3845	BW22		5/28/2023
970	WA	Centralia	3845	BW22		5/29/2023
971	WA	Centralia	3845	BW22		5/30/2023
972	WA	Centralia	3845	BW22		5/31/2023
973	WA	Centralia	3845	BW22		6/1/2023
974	WA	Centralia	3845	BW22		6/2/2023
975	WA	Centralia	3845	BW22		6/3/2023
976	WA	Centralia	3845	BW22		6/4/2023
977	WA	Centralia	3845	BW22		6/5/2023
978	WA	Centralia	3845	BW22		6/6/2023
979	WA	Centralia	3845	BW22		6/7/2023
980	WA	Centralia	3845	BW22		6/8/2023
981	WA	Centralia	3845	BW22		6/9/2023
982	WA	Centralia	3845	BW22		6/10/2023
983	WA	Centralia	3845	BW22		6/11/2023
984	WA	Centralia	3845	BW22		6/12/2023
985	WA	Centralia	3845	BW22		6/13/2023
986	WA	Centralia	3845	BW22		6/14/2023
987	WA	Centralia	3845	BW22		6/15/2023
988	WA	Centralia	3845	BW22		6/16/2023
989	WA	Centralia	3845	BW22		6/17/2023

	A	B	C	D	E	F
990	WA	Centralia	3845	BW22		6/18/2023
991	WA	Centralia	3845	BW22		6/19/2023
992	WA	Centralia	3845	BW22		6/20/2023
993	WA	Centralia	3845	BW22		6/21/2023
994	WA	Centralia	3845	BW22		6/22/2023
995	WA	Centralia	3845	BW22		6/23/2023
996	WA	Centralia	3845	BW22		6/24/2023
997	WA	Centralia	3845	BW22		6/25/2023
998	WA	Centralia	3845	BW22		6/26/2023
999	WA	Centralia	3845	BW22		6/27/2023
1000	WA	Centralia	3845	BW22		6/28/2023
1001	WA	Centralia	3845	BW22		6/29/2023
1002	WA	Centralia	3845	BW22		6/30/2023
1003	WA	Centralia	3845	BW22		7/1/2023
1004	WA	Centralia	3845	BW22		7/2/2023
1005	WA	Centralia	3845	BW22		7/3/2023
1006	WA	Centralia	3845	BW22		7/4/2023
1007	WA	Centralia	3845	BW22		7/5/2023
1008	WA	Centralia	3845	BW22		7/6/2023
1009	WA	Centralia	3845	BW22		7/7/2023
1010	WA	Centralia	3845	BW22		7/8/2023
1011	WA	Centralia	3845	BW22		7/9/2023
1012	WA	Centralia	3845	BW22		7/10/2023
1013	WA	Centralia	3845	BW22		7/11/2023
1014	WA	Centralia	3845	BW22		7/12/2023
1015	WA	Centralia	3845	BW22		7/13/2023
1016	WA	Centralia	3845	BW22		7/14/2023
1017	WA	Centralia	3845	BW22		7/15/2023
1018	WA	Centralia	3845	BW22		7/16/2023
1019	WA	Centralia	3845	BW22		7/17/2023
1020	WA	Centralia	3845	BW22		7/18/2023
1021	WA	Centralia	3845	BW22		7/19/2023
1022	WA	Centralia	3845	BW22		7/20/2023
1023	WA	Centralia	3845	BW22		7/21/2023
1024	WA	Centralia	3845	BW22		7/22/2023
1025	WA	Centralia	3845	BW22		7/23/2023
1026	WA	Centralia	3845	BW22		7/24/2023
1027	WA	Centralia	3845	BW22		7/25/2023
1028	WA	Centralia	3845	BW22		7/26/2023
1029	WA	Centralia	3845	BW22		7/27/2023
1030	WA	Centralia	3845	BW22		7/28/2023
1031	WA	Centralia	3845	BW22		7/29/2023
1032	WA	Centralia	3845	BW22		7/30/2023

	A	B	C	D	E	F
1033	WA	Centralia	3845	BW22		7/31/2023
1034	WA	Centralia	3845	BW22		8/1/2023
1035	WA	Centralia	3845	BW22		8/2/2023
1036	WA	Centralia	3845	BW22		8/3/2023
1037	WA	Centralia	3845	BW22		8/4/2023
1038	WA	Centralia	3845	BW22		8/5/2023
1039	WA	Centralia	3845	BW22		8/6/2023
1040	WA	Centralia	3845	BW22		8/7/2023
1041	WA	Centralia	3845	BW22		8/8/2023
1042	WA	Centralia	3845	BW22		8/9/2023
1043	WA	Centralia	3845	BW22		8/10/2023
1044	WA	Centralia	3845	BW22		8/11/2023
1045	WA	Centralia	3845	BW22		8/12/2023
1046	WA	Centralia	3845	BW22		8/13/2023
1047	WA	Centralia	3845	BW22		8/14/2023
1048	WA	Centralia	3845	BW22		8/15/2023
1049	WA	Centralia	3845	BW22		8/16/2023
1050	WA	Centralia	3845	BW22		8/17/2023
1051	WA	Centralia	3845	BW22		8/18/2023
1052	WA	Centralia	3845	BW22		8/19/2023
1053	WA	Centralia	3845	BW22		8/20/2023
1054	WA	Centralia	3845	BW22		8/21/2023
1055	WA	Centralia	3845	BW22		8/22/2023
1056	WA	Centralia	3845	BW22		8/23/2023
1057	WA	Centralia	3845	BW22		8/24/2023
1058	WA	Centralia	3845	BW22		8/25/2023
1059	WA	Centralia	3845	BW22		8/26/2023
1060	WA	Centralia	3845	BW22		8/27/2023
1061	WA	Centralia	3845	BW22		8/28/2023
1062	WA	Centralia	3845	BW22		8/29/2023
1063	WA	Centralia	3845	BW22		8/30/2023
1064	WA	Centralia	3845	BW22		8/31/2023
1065	WA	Centralia	3845	BW22		9/1/2023
1066	WA	Centralia	3845	BW22		9/2/2023
1067	WA	Centralia	3845	BW22		9/3/2023
1068	WA	Centralia	3845	BW22		9/4/2023
1069	WA	Centralia	3845	BW22		9/5/2023
1070	WA	Centralia	3845	BW22		9/6/2023
1071	WA	Centralia	3845	BW22		9/7/2023
1072	WA	Centralia	3845	BW22		9/8/2023
1073	WA	Centralia	3845	BW22		9/9/2023
1074	WA	Centralia	3845	BW22		9/10/2023
1075	WA	Centralia	3845	BW22		9/11/2023

	A	B	C	D	E	F
1076	WA	Centralia	3845	BW22		9/12/2023
1077	WA	Centralia	3845	BW22		9/13/2023
1078	WA	Centralia	3845	BW22		9/14/2023
1079	WA	Centralia	3845	BW22		9/15/2023
1080	WA	Centralia	3845	BW22		9/16/2023
1081	WA	Centralia	3845	BW22		9/17/2023
1082	WA	Centralia	3845	BW22		9/18/2023
1083	WA	Centralia	3845	BW22		9/19/2023
1084	WA	Centralia	3845	BW22		9/20/2023
1085	WA	Centralia	3845	BW22		9/21/2023
1086	WA	Centralia	3845	BW22		9/22/2023
1087	WA	Centralia	3845	BW22		9/23/2023
1088	WA	Centralia	3845	BW22		9/24/2023
1089	WA	Centralia	3845	BW22		9/25/2023
1090	WA	Centralia	3845	BW22		9/26/2023
1091	WA	Centralia	3845	BW22		9/27/2023
1092	WA	Centralia	3845	BW22		9/28/2023
1093	WA	Centralia	3845	BW22		9/29/2023
1094	WA	Centralia	3845	BW22		9/30/2023
1095	WA	Centralia	3845	BW22		10/1/2023
1096	WA	Centralia	3845	BW22		10/2/2023
1097	WA	Centralia	3845	BW22		10/3/2023
1098	WA	Centralia	3845	BW22		10/4/2023
1099	WA	Centralia	3845	BW22		10/5/2023
1100	WA	Centralia	3845	BW22		10/6/2023
1101	WA	Centralia	3845	BW22		10/7/2023
1102	WA	Centralia	3845	BW22		10/8/2023
1103	WA	Centralia	3845	BW22		10/9/2023
1104	WA	Centralia	3845	BW22		10/10/2023
1105	WA	Centralia	3845	BW22		10/11/2023
1106	WA	Centralia	3845	BW22		10/12/2023
1107	WA	Centralia	3845	BW22		10/13/2023
1108	WA	Centralia	3845	BW22		10/14/2023
1109	WA	Centralia	3845	BW22		10/15/2023
1110	WA	Centralia	3845	BW22		10/16/2023
1111	WA	Centralia	3845	BW22		10/17/2023
1112	WA	Centralia	3845	BW22		10/18/2023
1113	WA	Centralia	3845	BW22		10/19/2023
1114	WA	Centralia	3845	BW22		10/20/2023
1115	WA	Centralia	3845	BW22		10/21/2023
1116	WA	Centralia	3845	BW22		10/22/2023
1117	WA	Centralia	3845	BW22		10/23/2023
1118	WA	Centralia	3845	BW22		10/24/2023

	A	B	C	D	E	F
1119	WA	Centralia	3845	BW22		10/25/2023
1120	WA	Centralia	3845	BW22		10/26/2023
1121	WA	Centralia	3845	BW22		10/27/2023
1122	WA	Centralia	3845	BW22		10/28/2023
1123	WA	Centralia	3845	BW22		10/29/2023
1124	WA	Centralia	3845	BW22		10/30/2023
1125	WA	Centralia	3845	BW22		10/31/2023
1126	WA	Centralia	3845	BW22		11/1/2023
1127	WA	Centralia	3845	BW22		11/2/2023
1128	WA	Centralia	3845	BW22		11/3/2023
1129	WA	Centralia	3845	BW22		11/4/2023
1130	WA	Centralia	3845	BW22		11/5/2023
1131	WA	Centralia	3845	BW22		11/6/2023
1132	WA	Centralia	3845	BW22		11/7/2023
1133	WA	Centralia	3845	BW22		11/8/2023
1134	WA	Centralia	3845	BW22		11/9/2023
1135	WA	Centralia	3845	BW22		11/10/2023
1136	WA	Centralia	3845	BW22		11/11/2023
1137	WA	Centralia	3845	BW22		11/12/2023
1138	WA	Centralia	3845	BW22		11/13/2023
1139	WA	Centralia	3845	BW22		11/14/2023
1140	WA	Centralia	3845	BW22		11/15/2023
1141	WA	Centralia	3845	BW22		11/16/2023
1142	WA	Centralia	3845	BW22		11/17/2023
1143	WA	Centralia	3845	BW22		11/18/2023
1144	WA	Centralia	3845	BW22		11/19/2023
1145	WA	Centralia	3845	BW22		11/20/2023
1146	WA	Centralia	3845	BW22		11/21/2023
1147	WA	Centralia	3845	BW22		11/22/2023
1148	WA	Centralia	3845	BW22		11/23/2023
1149	WA	Centralia	3845	BW22		11/24/2023
1150	WA	Centralia	3845	BW22		11/25/2023
1151	WA	Centralia	3845	BW22		11/26/2023
1152	WA	Centralia	3845	BW22		11/27/2023
1153	WA	Centralia	3845	BW22		11/28/2023
1154	WA	Centralia	3845	BW22		11/29/2023
1155	WA	Centralia	3845	BW22		11/30/2023
1156	WA	Centralia	3845	BW22		12/1/2023
1157	WA	Centralia	3845	BW22		12/2/2023
1158	WA	Centralia	3845	BW22		12/3/2023
1159	WA	Centralia	3845	BW22		12/4/2023
1160	WA	Centralia	3845	BW22		12/5/2023
1161	WA	Centralia	3845	BW22		12/6/2023

	A	B	C	D	E	F
1162	WA	Centralia	3845	BW22		12/7/2023
1163	WA	Centralia	3845	BW22		12/8/2023
1164	WA	Centralia	3845	BW22		12/9/2023
1165	WA	Centralia	3845	BW22		12/10/2023
1166	WA	Centralia	3845	BW22		12/11/2023
1167	WA	Centralia	3845	BW22		12/12/2023
1168	WA	Centralia	3845	BW22		12/13/2023
1169	WA	Centralia	3845	BW22		12/14/2023
1170	WA	Centralia	3845	BW22		12/15/2023
1171	WA	Centralia	3845	BW22		12/16/2023
1172	WA	Centralia	3845	BW22		12/17/2023
1173	WA	Centralia	3845	BW22		12/18/2023
1174	WA	Centralia	3845	BW22		12/19/2023
1175	WA	Centralia	3845	BW22		12/20/2023
1176	WA	Centralia	3845	BW22		12/21/2023
1177	WA	Centralia	3845	BW22		12/22/2023
1178	WA	Centralia	3845	BW22		12/23/2023
1179	WA	Centralia	3845	BW22		12/24/2023
1180	WA	Centralia	3845	BW22		12/25/2023
1181	WA	Centralia	3845	BW22		12/26/2023
1182	WA	Centralia	3845	BW22		12/27/2023
1183	WA	Centralia	3845	BW22		12/28/2023
1184	WA	Centralia	3845	BW22		12/29/2023
1185	WA	Centralia	3845	BW22		12/30/2023
1186	WA	Centralia	3845	BW22		12/31/2023
1187	WA	Centralia	3845	BW22		1/1/2024
1188	WA	Centralia	3845	BW22		1/2/2024
1189	WA	Centralia	3845	BW22		1/3/2024
1190	WA	Centralia	3845	BW22		1/4/2024
1191	WA	Centralia	3845	BW22		1/5/2024
1192	WA	Centralia	3845	BW22		1/6/2024
1193	WA	Centralia	3845	BW22		1/7/2024
1194	WA	Centralia	3845	BW22		1/8/2024
1195	WA	Centralia	3845	BW22		1/9/2024
1196	WA	Centralia	3845	BW22		1/10/2024
1197	WA	Centralia	3845	BW22		1/11/2024
1198	WA	Centralia	3845	BW22		1/12/2024
1199	WA	Centralia	3845	BW22		1/13/2024
1200	WA	Centralia	3845	BW22		1/14/2024
1201	WA	Centralia	3845	BW22		1/15/2024
1202	WA	Centralia	3845	BW22		1/16/2024
1203	WA	Centralia	3845	BW22		1/17/2024
1204	WA	Centralia	3845	BW22		1/18/2024

	A	B	C	D	E	F
1205	WA	Centralia	3845	BW22		1/19/2024
1206	WA	Centralia	3845	BW22		1/20/2024
1207	WA	Centralia	3845	BW22		1/21/2024
1208	WA	Centralia	3845	BW22		1/22/2024
1209	WA	Centralia	3845	BW22		1/23/2024
1210	WA	Centralia	3845	BW22		1/24/2024
1211	WA	Centralia	3845	BW22		1/25/2024
1212	WA	Centralia	3845	BW22		1/26/2024
1213	WA	Centralia	3845	BW22		1/27/2024
1214	WA	Centralia	3845	BW22		1/28/2024
1215	WA	Centralia	3845	BW22		1/29/2024
1216	WA	Centralia	3845	BW22		1/30/2024
1217	WA	Centralia	3845	BW22		1/31/2024
1218	WA	Centralia	3845	BW22		2/1/2024
1219	WA	Centralia	3845	BW22		2/2/2024
1220	WA	Centralia	3845	BW22		2/3/2024
1221	WA	Centralia	3845	BW22		2/4/2024
1222	WA	Centralia	3845	BW22		2/5/2024
1223	WA	Centralia	3845	BW22		2/6/2024
1224	WA	Centralia	3845	BW22		2/7/2024
1225	WA	Centralia	3845	BW22		2/8/2024
1226	WA	Centralia	3845	BW22		2/9/2024
1227	WA	Centralia	3845	BW22		2/10/2024
1228	WA	Centralia	3845	BW22		2/11/2024
1229	WA	Centralia	3845	BW22		2/12/2024
1230	WA	Centralia	3845	BW22		2/13/2024
1231	WA	Centralia	3845	BW22		2/14/2024
1232	WA	Centralia	3845	BW22		2/15/2024
1233	WA	Centralia	3845	BW22		2/16/2024
1234	WA	Centralia	3845	BW22		2/17/2024
1235	WA	Centralia	3845	BW22		2/18/2024
1236	WA	Centralia	3845	BW22		2/19/2024
1237	WA	Centralia	3845	BW22		2/20/2024
1238	WA	Centralia	3845	BW22		2/21/2024
1239	WA	Centralia	3845	BW22		2/22/2024
1240	WA	Centralia	3845	BW22		2/23/2024
1241	WA	Centralia	3845	BW22		2/24/2024
1242	WA	Centralia	3845	BW22		2/25/2024
1243	WA	Centralia	3845	BW22		2/26/2024
1244	WA	Centralia	3845	BW22		2/27/2024
1245	WA	Centralia	3845	BW22		2/28/2024
1246	WA	Centralia	3845	BW22		2/29/2024
1247	WA	Centralia	3845	BW22		3/1/2024

	A	B	C	D	E	F
1248	WA	Centralia	3845	BW22		3/2/2024
1249	WA	Centralia	3845	BW22		3/3/2024
1250	WA	Centralia	3845	BW22		3/4/2024
1251	WA	Centralia	3845	BW22		3/5/2024
1252	WA	Centralia	3845	BW22		3/6/2024
1253	WA	Centralia	3845	BW22		3/7/2024
1254	WA	Centralia	3845	BW22		3/8/2024
1255	WA	Centralia	3845	BW22		3/9/2024
1256	WA	Centralia	3845	BW22		3/10/2024
1257	WA	Centralia	3845	BW22		3/11/2024
1258	WA	Centralia	3845	BW22		3/12/2024
1259	WA	Centralia	3845	BW22		3/13/2024
1260	WA	Centralia	3845	BW22		3/14/2024
1261	WA	Centralia	3845	BW22		3/15/2024
1262	WA	Centralia	3845	BW22		3/16/2024
1263	WA	Centralia	3845	BW22		3/17/2024
1264	WA	Centralia	3845	BW22		3/18/2024
1265	WA	Centralia	3845	BW22		3/19/2024
1266	WA	Centralia	3845	BW22		3/20/2024
1267	WA	Centralia	3845	BW22		3/21/2024
1268	WA	Centralia	3845	BW22		3/22/2024
1269	WA	Centralia	3845	BW22		3/23/2024
1270	WA	Centralia	3845	BW22		3/24/2024
1271	WA	Centralia	3845	BW22		3/25/2024
1272	WA	Centralia	3845	BW22		3/26/2024
1273	WA	Centralia	3845	BW22		3/27/2024
1274	WA	Centralia	3845	BW22		3/28/2024
1275	WA	Centralia	3845	BW22		3/29/2024
1276	WA	Centralia	3845	BW22		3/30/2024
1277	WA	Centralia	3845	BW22		3/31/2024
1278	WA	Centralia	3845	BW22		4/1/2024
1279	WA	Centralia	3845	BW22		4/2/2024
1280	WA	Centralia	3845	BW22		4/3/2024
1281	WA	Centralia	3845	BW22		4/4/2024
1282	WA	Centralia	3845	BW22		4/5/2024
1283	WA	Centralia	3845	BW22		4/6/2024
1284	WA	Centralia	3845	BW22		4/7/2024
1285	WA	Centralia	3845	BW22		4/8/2024
1286	WA	Centralia	3845	BW22		4/9/2024
1287	WA	Centralia	3845	BW22		4/10/2024
1288	WA	Centralia	3845	BW22		4/11/2024
1289	WA	Centralia	3845	BW22		4/12/2024
1290	WA	Centralia	3845	BW22		4/13/2024

	A	B	C	D	E	F
1291	WA	Centralia	3845	BW22		4/14/2024
1292	WA	Centralia	3845	BW22		4/15/2024
1293	WA	Centralia	3845	BW22		4/16/2024
1294	WA	Centralia	3845	BW22		4/17/2024
1295	WA	Centralia	3845	BW22		4/18/2024
1296	WA	Centralia	3845	BW22		4/19/2024
1297	WA	Centralia	3845	BW22		4/20/2024
1298	WA	Centralia	3845	BW22		4/21/2024
1299	WA	Centralia	3845	BW22		4/22/2024
1300	WA	Centralia	3845	BW22		4/23/2024
1301	WA	Centralia	3845	BW22		4/24/2024
1302	WA	Centralia	3845	BW22		4/25/2024
1303	WA	Centralia	3845	BW22		4/26/2024
1304	WA	Centralia	3845	BW22		4/27/2024
1305	WA	Centralia	3845	BW22		4/28/2024
1306	WA	Centralia	3845	BW22		4/29/2024
1307	WA	Centralia	3845	BW22		4/30/2024
1308	WA	Centralia	3845	BW22		5/1/2024
1309	WA	Centralia	3845	BW22		5/2/2024
1310	WA	Centralia	3845	BW22		5/3/2024
1311	WA	Centralia	3845	BW22		5/4/2024
1312	WA	Centralia	3845	BW22		5/5/2024
1313	WA	Centralia	3845	BW22		5/6/2024
1314	WA	Centralia	3845	BW22		5/7/2024
1315	WA	Centralia	3845	BW22		5/8/2024
1316	WA	Centralia	3845	BW22		5/9/2024
1317	WA	Centralia	3845	BW22		5/10/2024
1318	WA	Centralia	3845	BW22		5/11/2024
1319	WA	Centralia	3845	BW22		5/12/2024
1320	WA	Centralia	3845	BW22		5/13/2024
1321	WA	Centralia	3845	BW22		5/14/2024
1322	WA	Centralia	3845	BW22		5/15/2024
1323	WA	Centralia	3845	BW22		5/16/2024
1324	WA	Centralia	3845	BW22		5/17/2024
1325	WA	Centralia	3845	BW22		5/18/2024
1326	WA	Centralia	3845	BW22		5/19/2024
1327	WA	Centralia	3845	BW22		5/20/2024
1328	WA	Centralia	3845	BW22		5/21/2024
1329	WA	Centralia	3845	BW22		5/22/2024
1330	WA	Centralia	3845	BW22		5/23/2024
1331	WA	Centralia	3845	BW22		5/24/2024
1332	WA	Centralia	3845	BW22		5/25/2024
1333	WA	Centralia	3845	BW22		5/26/2024

	A	B	C	D	E	F
1334	WA	Centralia	3845	BW22		5/27/2024
1335	WA	Centralia	3845	BW22		5/28/2024
1336	WA	Centralia	3845	BW22		5/29/2024
1337	WA	Centralia	3845	BW22		5/30/2024
1338	WA	Centralia	3845	BW22		5/31/2024
1339	WA	Centralia	3845	BW22		6/1/2024
1340	WA	Centralia	3845	BW22		6/2/2024
1341	WA	Centralia	3845	BW22		6/3/2024
1342	WA	Centralia	3845	BW22		6/4/2024
1343	WA	Centralia	3845	BW22		6/5/2024
1344	WA	Centralia	3845	BW22		6/6/2024
1345	WA	Centralia	3845	BW22		6/7/2024
1346	WA	Centralia	3845	BW22		6/8/2024
1347	WA	Centralia	3845	BW22		6/9/2024
1348	WA	Centralia	3845	BW22		6/10/2024
1349	WA	Centralia	3845	BW22		6/11/2024
1350	WA	Centralia	3845	BW22		6/12/2024
1351	WA	Centralia	3845	BW22		6/13/2024
1352	WA	Centralia	3845	BW22		6/14/2024
1353	WA	Centralia	3845	BW22		6/15/2024
1354	WA	Centralia	3845	BW22		6/16/2024
1355	WA	Centralia	3845	BW22		6/17/2024
1356	WA	Centralia	3845	BW22		6/18/2024
1357	WA	Centralia	3845	BW22		6/19/2024
1358	WA	Centralia	3845	BW22		6/20/2024
1359	WA	Centralia	3845	BW22		6/21/2024
1360	WA	Centralia	3845	BW22		6/22/2024
1361	WA	Centralia	3845	BW22		6/23/2024
1362	WA	Centralia	3845	BW22		6/24/2024
1363	WA	Centralia	3845	BW22		6/25/2024
1364	WA	Centralia	3845	BW22		6/26/2024
1365	WA	Centralia	3845	BW22		6/27/2024
1366	WA	Centralia	3845	BW22		6/28/2024
1367	WA	Centralia	3845	BW22		6/29/2024
1368	WA	Centralia	3845	BW22		6/30/2024
1369	WA	Centralia	3845	BW22		7/1/2024
1370	WA	Centralia	3845	BW22		7/2/2024
1371	WA	Centralia	3845	BW22		7/3/2024
1372	WA	Centralia	3845	BW22		7/4/2024
1373	WA	Centralia	3845	BW22		7/5/2024
1374	WA	Centralia	3845	BW22		7/6/2024
1375	WA	Centralia	3845	BW22		7/7/2024
1376	WA	Centralia	3845	BW22		7/8/2024

	A	B	C	D	E	F
1377	WA	Centralia	3845	BW22		7/9/2024
1378	WA	Centralia	3845	BW22		7/10/2024
1379	WA	Centralia	3845	BW22		7/11/2024
1380	WA	Centralia	3845	BW22		7/12/2024
1381	WA	Centralia	3845	BW22		7/13/2024
1382	WA	Centralia	3845	BW22		7/14/2024
1383	WA	Centralia	3845	BW22		7/15/2024
1384	WA	Centralia	3845	BW22		7/16/2024
1385	WA	Centralia	3845	BW22		7/17/2024
1386	WA	Centralia	3845	BW22		7/18/2024
1387	WA	Centralia	3845	BW22		7/19/2024
1388	WA	Centralia	3845	BW22		7/20/2024
1389	WA	Centralia	3845	BW22		7/21/2024
1390	WA	Centralia	3845	BW22		7/22/2024
1391	WA	Centralia	3845	BW22		7/23/2024
1392	WA	Centralia	3845	BW22		7/24/2024
1393	WA	Centralia	3845	BW22		7/25/2024
1394	WA	Centralia	3845	BW22		7/26/2024
1395	WA	Centralia	3845	BW22		7/27/2024
1396	WA	Centralia	3845	BW22		7/28/2024
1397	WA	Centralia	3845	BW22		7/29/2024
1398	WA	Centralia	3845	BW22		7/30/2024
1399	WA	Centralia	3845	BW22		7/31/2024
1400	WA	Centralia	3845	BW22		8/1/2024
1401	WA	Centralia	3845	BW22		8/2/2024
1402	WA	Centralia	3845	BW22		8/3/2024
1403	WA	Centralia	3845	BW22		8/4/2024
1404	WA	Centralia	3845	BW22		8/5/2024
1405	WA	Centralia	3845	BW22		8/6/2024
1406	WA	Centralia	3845	BW22		8/7/2024
1407	WA	Centralia	3845	BW22		8/8/2024
1408	WA	Centralia	3845	BW22		8/9/2024
1409	WA	Centralia	3845	BW22		8/10/2024
1410	WA	Centralia	3845	BW22		8/11/2024
1411	WA	Centralia	3845	BW22		8/12/2024
1412	WA	Centralia	3845	BW22		8/13/2024
1413	WA	Centralia	3845	BW22		8/14/2024
1414	WA	Centralia	3845	BW22		8/15/2024
1415	WA	Centralia	3845	BW22		8/16/2024
1416	WA	Centralia	3845	BW22		8/17/2024
1417	WA	Centralia	3845	BW22		8/18/2024
1418	WA	Centralia	3845	BW22		8/19/2024
1419	WA	Centralia	3845	BW22		8/20/2024

	A	B	C	D	E	F
1420	WA	Centralia	3845	BW22		8/21/2024
1421	WA	Centralia	3845	BW22		8/22/2024
1422	WA	Centralia	3845	BW22		8/23/2024
1423	WA	Centralia	3845	BW22		8/24/2024
1424	WA	Centralia	3845	BW22		8/25/2024
1425	WA	Centralia	3845	BW22		8/26/2024
1426	WA	Centralia	3845	BW22		8/27/2024
1427	WA	Centralia	3845	BW22		8/28/2024
1428	WA	Centralia	3845	BW22		8/29/2024
1429	WA	Centralia	3845	BW22		8/30/2024
1430	WA	Centralia	3845	BW22		8/31/2024
1431	WA	Centralia	3845	BW22		9/1/2024
1432	WA	Centralia	3845	BW22		9/2/2024
1433	WA	Centralia	3845	BW22		9/3/2024
1434	WA	Centralia	3845	BW22		9/4/2024
1435	WA	Centralia	3845	BW22		9/5/2024
1436	WA	Centralia	3845	BW22		9/6/2024
1437	WA	Centralia	3845	BW22		9/7/2024
1438	WA	Centralia	3845	BW22		9/8/2024
1439	WA	Centralia	3845	BW22		9/9/2024
1440	WA	Centralia	3845	BW22		9/10/2024
1441	WA	Centralia	3845	BW22		9/11/2024
1442	WA	Centralia	3845	BW22		9/12/2024
1443	WA	Centralia	3845	BW22		9/13/2024
1444	WA	Centralia	3845	BW22		9/14/2024
1445	WA	Centralia	3845	BW22		9/15/2024
1446	WA	Centralia	3845	BW22		9/16/2024
1447	WA	Centralia	3845	BW22		9/17/2024
1448	WA	Centralia	3845	BW22		9/18/2024
1449	WA	Centralia	3845	BW22		9/19/2024
1450	WA	Centralia	3845	BW22		9/20/2024
1451	WA	Centralia	3845	BW22		9/21/2024
1452	WA	Centralia	3845	BW22		9/22/2024
1453	WA	Centralia	3845	BW22		9/23/2024
1454	WA	Centralia	3845	BW22		9/24/2024
1455	WA	Centralia	3845	BW22		9/25/2024
1456	WA	Centralia	3845	BW22		9/26/2024
1457	WA	Centralia	3845	BW22		9/27/2024
1458	WA	Centralia	3845	BW22		9/28/2024
1459	WA	Centralia	3845	BW22		9/29/2024
1460	WA	Centralia	3845	BW22		9/30/2024
1461	WA	Centralia	3845	BW22		10/1/2024
1462	WA	Centralia	3845	BW22		10/2/2024

	A	B	C	D	E	F
1463	WA	Centralia	3845	BW22		10/3/2024
1464	WA	Centralia	3845	BW22		10/4/2024
1465	WA	Centralia	3845	BW22		10/5/2024
1466	WA	Centralia	3845	BW22		10/6/2024
1467	WA	Centralia	3845	BW22		10/7/2024
1468	WA	Centralia	3845	BW22		10/8/2024
1469	WA	Centralia	3845	BW22		10/9/2024
1470	WA	Centralia	3845	BW22		10/10/2024
1471	WA	Centralia	3845	BW22		10/11/2024
1472	WA	Centralia	3845	BW22		10/12/2024
1473	WA	Centralia	3845	BW22		10/13/2024
1474	WA	Centralia	3845	BW22		10/14/2024
1475	WA	Centralia	3845	BW22		10/15/2024
1476	WA	Centralia	3845	BW22		10/16/2024
1477	WA	Centralia	3845	BW22		10/17/2024
1478	WA	Centralia	3845	BW22		10/18/2024
1479	WA	Centralia	3845	BW22		10/19/2024
1480	WA	Centralia	3845	BW22		10/20/2024
1481	WA	Centralia	3845	BW22		10/21/2024
1482	WA	Centralia	3845	BW22		10/22/2024
1483	WA	Centralia	3845	BW22		10/23/2024
1484	WA	Centralia	3845	BW22		10/24/2024
1485	WA	Centralia	3845	BW22		10/25/2024
1486	WA	Centralia	3845	BW22		10/26/2024
1487	WA	Centralia	3845	BW22		10/27/2024
1488	WA	Centralia	3845	BW22		10/28/2024
1489	WA	Centralia	3845	BW22		10/29/2024
1490	WA	Centralia	3845	BW22		10/30/2024
1491	WA	Centralia	3845	BW22		10/31/2024
1492	WA	Centralia	3845	BW22		11/1/2024
1493	WA	Centralia	3845	BW22		11/2/2024
1494	WA	Centralia	3845	BW22		11/3/2024
1495	WA	Centralia	3845	BW22		11/4/2024
1496	WA	Centralia	3845	BW22		11/5/2024
1497	WA	Centralia	3845	BW22		11/6/2024
1498	WA	Centralia	3845	BW22		11/7/2024
1499	WA	Centralia	3845	BW22		11/8/2024
1500	WA	Centralia	3845	BW22		11/9/2024
1501	WA	Centralia	3845	BW22		11/10/2024
1502	WA	Centralia	3845	BW22		11/11/2024
1503	WA	Centralia	3845	BW22		11/12/2024
1504	WA	Centralia	3845	BW22		11/13/2024
1505	WA	Centralia	3845	BW22		11/14/2024

	A	B	C	D	E	F
1506	WA	Centralia	3845	BW22		11/15/2024
1507	WA	Centralia	3845	BW22		11/16/2024
1508	WA	Centralia	3845	BW22		11/17/2024
1509	WA	Centralia	3845	BW22		11/18/2024
1510	WA	Centralia	3845	BW22		11/19/2024
1511	WA	Centralia	3845	BW22		11/20/2024
1512	WA	Centralia	3845	BW22		11/21/2024
1513	WA	Centralia	3845	BW22		11/22/2024
1514	WA	Centralia	3845	BW22		11/23/2024
1515	WA	Centralia	3845	BW22		11/24/2024
1516	WA	Centralia	3845	BW22		11/25/2024
1517	WA	Centralia	3845	BW22		11/26/2024
1518	WA	Centralia	3845	BW22		11/27/2024
1519	WA	Centralia	3845	BW22		11/28/2024
1520	WA	Centralia	3845	BW22		11/29/2024
1521	WA	Centralia	3845	BW22		11/30/2024
1522	WA	Centralia	3845	BW22		12/1/2024
1523	WA	Centralia	3845	BW22		12/2/2024
1524	WA	Centralia	3845	BW22		12/3/2024
1525	WA	Centralia	3845	BW22		12/4/2024
1526	WA	Centralia	3845	BW22		12/5/2024
1527	WA	Centralia	3845	BW22		12/6/2024
1528	WA	Centralia	3845	BW22		12/7/2024
1529	WA	Centralia	3845	BW22		12/8/2024
1530	WA	Centralia	3845	BW22		12/9/2024
1531	WA	Centralia	3845	BW22		12/10/2024
1532	WA	Centralia	3845	BW22		12/11/2024
1533	WA	Centralia	3845	BW22		12/12/2024
1534	WA	Centralia	3845	BW22		12/13/2024
1535	WA	Centralia	3845	BW22		12/14/2024
1536	WA	Centralia	3845	BW22		12/15/2024
1537	WA	Centralia	3845	BW22		12/16/2024
1538	WA	Centralia	3845	BW22		12/17/2024
1539	WA	Centralia	3845	BW22		12/18/2024
1540	WA	Centralia	3845	BW22		12/19/2024
1541	WA	Centralia	3845	BW22		12/20/2024
1542	WA	Centralia	3845	BW22		12/21/2024
1543	WA	Centralia	3845	BW22		12/22/2024
1544	WA	Centralia	3845	BW22		12/23/2024
1545	WA	Centralia	3845	BW22		12/24/2024
1546	WA	Centralia	3845	BW22		12/25/2024
1547	WA	Centralia	3845	BW22		12/26/2024
1548	WA	Centralia	3845	BW22		12/27/2024

	A	B	C	D	E	F
1549	WA	Centralia	3845	BW22		12/28/2024
1550	WA	Centralia	3845	BW22		12/29/2024
1551	WA	Centralia	3845	BW22		12/30/2024
1552	WA	Centralia	3845	BW22		12/31/2024
1553	WA	Centralia	3845	BW22		1/1/2025
1554	WA	Centralia	3845	BW22		1/2/2025
1555	WA	Centralia	3845	BW22		1/3/2025
1556	WA	Centralia	3845	BW22		1/4/2025
1557	WA	Centralia	3845	BW22		1/5/2025
1558	WA	Centralia	3845	BW22		1/6/2025
1559	WA	Centralia	3845	BW22		1/7/2025
1560	WA	Centralia	3845	BW22		1/8/2025
1561	WA	Centralia	3845	BW22		1/9/2025
1562	WA	Centralia	3845	BW22		1/10/2025
1563	WA	Centralia	3845	BW22		1/11/2025
1564	WA	Centralia	3845	BW22		1/12/2025
1565	WA	Centralia	3845	BW22		1/13/2025
1566	WA	Centralia	3845	BW22		1/14/2025
1567	WA	Centralia	3845	BW22		1/15/2025
1568	WA	Centralia	3845	BW22		1/16/2025
1569	WA	Centralia	3845	BW22		1/17/2025
1570	WA	Centralia	3845	BW22		1/18/2025
1571	WA	Centralia	3845	BW22		1/19/2025
1572	WA	Centralia	3845	BW22		1/20/2025
1573	WA	Centralia	3845	BW22		1/21/2025
1574	WA	Centralia	3845	BW22		1/22/2025
1575	WA	Centralia	3845	BW22		1/23/2025
1576	WA	Centralia	3845	BW22		1/24/2025
1577	WA	Centralia	3845	BW22		1/25/2025
1578	WA	Centralia	3845	BW22		1/26/2025
1579	WA	Centralia	3845	BW22		1/27/2025
1580	WA	Centralia	3845	BW22		1/28/2025
1581	WA	Centralia	3845	BW22		1/29/2025
1582	WA	Centralia	3845	BW22		1/30/2025
1583	WA	Centralia	3845	BW22		1/31/2025
1584	WA	Centralia	3845	BW22		2/1/2025
1585	WA	Centralia	3845	BW22		2/2/2025
1586	WA	Centralia	3845	BW22		2/3/2025
1587	WA	Centralia	3845	BW22		2/4/2025
1588	WA	Centralia	3845	BW22		2/5/2025
1589	WA	Centralia	3845	BW22		2/6/2025
1590	WA	Centralia	3845	BW22		2/7/2025
1591	WA	Centralia	3845	BW22		2/8/2025

	A	B	C	D	E	F
1592	WA	Centralia	3845	BW22		2/9/2025
1593	WA	Centralia	3845	BW22		2/10/2025
1594	WA	Centralia	3845	BW22		2/11/2025
1595	WA	Centralia	3845	BW22		2/12/2025
1596	WA	Centralia	3845	BW22		2/13/2025
1597	WA	Centralia	3845	BW22		2/14/2025
1598	WA	Centralia	3845	BW22		2/15/2025
1599	WA	Centralia	3845	BW22		2/16/2025
1600	WA	Centralia	3845	BW22		2/17/2025
1601	WA	Centralia	3845	BW22		2/18/2025
1602	WA	Centralia	3845	BW22		2/19/2025
1603	WA	Centralia	3845	BW22		2/20/2025
1604	WA	Centralia	3845	BW22		2/21/2025
1605	WA	Centralia	3845	BW22		2/22/2025
1606	WA	Centralia	3845	BW22		2/23/2025
1607	WA	Centralia	3845	BW22		2/24/2025
1608	WA	Centralia	3845	BW22		2/25/2025
1609	WA	Centralia	3845	BW22		2/26/2025
1610	WA	Centralia	3845	BW22		2/27/2025
1611	WA	Centralia	3845	BW22		2/28/2025
1612	WA	Centralia	3845	BW22		3/1/2025
1613	WA	Centralia	3845	BW22		3/2/2025
1614	WA	Centralia	3845	BW22		3/3/2025
1615	WA	Centralia	3845	BW22		3/4/2025
1616	WA	Centralia	3845	BW22		3/5/2025
1617	WA	Centralia	3845	BW22		3/6/2025
1618	WA	Centralia	3845	BW22		3/7/2025
1619	WA	Centralia	3845	BW22		3/8/2025
1620	WA	Centralia	3845	BW22		3/9/2025
1621	WA	Centralia	3845	BW22		3/10/2025
1622	WA	Centralia	3845	BW22		3/11/2025
1623	WA	Centralia	3845	BW22		3/12/2025
1624	WA	Centralia	3845	BW22		3/13/2025
1625	WA	Centralia	3845	BW22		3/14/2025
1626	WA	Centralia	3845	BW22		3/15/2025
1627	WA	Centralia	3845	BW22		3/16/2025
1628	WA	Centralia	3845	BW22		3/17/2025
1629	WA	Centralia	3845	BW22		3/18/2025
1630	WA	Centralia	3845	BW22		3/19/2025
1631	WA	Centralia	3845	BW22		3/20/2025
1632	WA	Centralia	3845	BW22		3/21/2025
1633	WA	Centralia	3845	BW22		3/22/2025
1634	WA	Centralia	3845	BW22		3/23/2025

	A	B	C	D	E	F
1635	WA	Centralia	3845	BW22		3/24/2025
1636	WA	Centralia	3845	BW22		3/25/2025
1637	WA	Centralia	3845	BW22		3/26/2025
1638	WA	Centralia	3845	BW22		3/27/2025
1639	WA	Centralia	3845	BW22		3/28/2025
1640	WA	Centralia	3845	BW22		3/29/2025
1641	WA	Centralia	3845	BW22		3/30/2025
1642	WA	Centralia	3845	BW22		3/31/2025
1643	WA	Centralia	3845	BW22		4/1/2025
1644	WA	Centralia	3845	BW22		4/2/2025
1645	WA	Centralia	3845	BW22		4/3/2025
1646	WA	Centralia	3845	BW22		4/4/2025
1647	WA	Centralia	3845	BW22		4/5/2025
1648	WA	Centralia	3845	BW22		4/6/2025
1649	WA	Centralia	3845	BW22		4/7/2025
1650	WA	Centralia	3845	BW22		4/8/2025
1651	WA	Centralia	3845	BW22		4/9/2025
1652	WA	Centralia	3845	BW22		4/10/2025
1653	WA	Centralia	3845	BW22		4/11/2025
1654	WA	Centralia	3845	BW22		4/12/2025
1655	WA	Centralia	3845	BW22		4/13/2025
1656	WA	Centralia	3845	BW22		4/14/2025
1657	WA	Centralia	3845	BW22		4/15/2025
1658	WA	Centralia	3845	BW22		4/16/2025
1659	WA	Centralia	3845	BW22		4/17/2025
1660	WA	Centralia	3845	BW22		4/18/2025
1661	WA	Centralia	3845	BW22		4/19/2025
1662	WA	Centralia	3845	BW22		4/20/2025
1663	WA	Centralia	3845	BW22		4/21/2025
1664	WA	Centralia	3845	BW22		4/22/2025
1665	WA	Centralia	3845	BW22		4/23/2025
1666	WA	Centralia	3845	BW22		4/24/2025
1667	WA	Centralia	3845	BW22		4/25/2025
1668	WA	Centralia	3845	BW22		4/26/2025
1669	WA	Centralia	3845	BW22		4/27/2025
1670	WA	Centralia	3845	BW22		4/28/2025
1671	WA	Centralia	3845	BW22		4/29/2025
1672	WA	Centralia	3845	BW22		4/30/2025
1673	WA	Centralia	3845	BW22		5/1/2025
1674	WA	Centralia	3845	BW22		5/2/2025
1675	WA	Centralia	3845	BW22		5/3/2025
1676	WA	Centralia	3845	BW22		5/4/2025
1677	WA	Centralia	3845	BW22		5/5/2025

	A	B	C	D	E	F
1678	WA	Centralia	3845	BW22		5/6/2025
1679	WA	Centralia	3845	BW22		5/7/2025
1680	WA	Centralia	3845	BW22		5/8/2025
1681	WA	Centralia	3845	BW22		5/9/2025
1682	WA	Centralia	3845	BW22		5/10/2025
1683	WA	Centralia	3845	BW22		5/11/2025
1684	WA	Centralia	3845	BW22		5/12/2025
1685	WA	Centralia	3845	BW22		5/13/2025
1686	WA	Centralia	3845	BW22		5/14/2025
1687	WA	Centralia	3845	BW22		5/15/2025
1688	WA	Centralia	3845	BW22		5/16/2025
1689	WA	Centralia	3845	BW22		5/17/2025
1690	WA	Centralia	3845	BW22		5/18/2025
1691	WA	Centralia	3845	BW22		5/19/2025
1692	WA	Centralia	3845	BW22		5/20/2025
1693	WA	Centralia	3845	BW22		5/21/2025
1694	WA	Centralia	3845	BW22		5/22/2025
1695	WA	Centralia	3845	BW22		5/23/2025
1696	WA	Centralia	3845	BW22		5/24/2025
1697	WA	Centralia	3845	BW22		5/25/2025
1698	WA	Centralia	3845	BW22		5/26/2025
1699	WA	Centralia	3845	BW22		5/27/2025
1700	WA	Centralia	3845	BW22		5/28/2025
1701	WA	Centralia	3845	BW22		5/29/2025
1702	WA	Centralia	3845	BW22		5/30/2025
1703	WA	Centralia	3845	BW22		5/31/2025
1704	WA	Centralia	3845	BW22		6/1/2025
1705	WA	Centralia	3845	BW22		6/2/2025
1706	WA	Centralia	3845	BW22		6/3/2025
1707	WA	Centralia	3845	BW22		6/4/2025
1708	WA	Centralia	3845	BW22		6/5/2025
1709	WA	Centralia	3845	BW22		6/6/2025
1710	WA	Centralia	3845	BW22		6/7/2025
1711	WA	Centralia	3845	BW22		6/8/2025
1712	WA	Centralia	3845	BW22		6/9/2025
1713	WA	Centralia	3845	BW22		6/10/2025
1714	WA	Centralia	3845	BW22		6/11/2025
1715	WA	Centralia	3845	BW22		6/12/2025
1716	WA	Centralia	3845	BW22		6/13/2025
1717	WA	Centralia	3845	BW22		6/14/2025
1718	WA	Centralia	3845	BW22		6/15/2025
1719	WA	Centralia	3845	BW22		6/16/2025
1720	WA	Centralia	3845	BW22		6/17/2025

	A	B	C	D	E	F
1721	WA	Centralia	3845	BW22		6/18/2025
1722	WA	Centralia	3845	BW22		6/19/2025
1723	WA	Centralia	3845	BW22		6/20/2025
1724	WA	Centralia	3845	BW22		6/21/2025
1725	WA	Centralia	3845	BW22		6/22/2025
1726	WA	Centralia	3845	BW22		6/23/2025
1727	WA	Centralia	3845	BW22		6/24/2025
1728	WA	Centralia	3845	BW22		6/25/2025
1729	WA	Centralia	3845	BW22		6/26/2025
1730	WA	Centralia	3845	BW22		6/27/2025
1731	WA	Centralia	3845	BW22		6/28/2025
1732	WA	Centralia	3845	BW22		6/29/2025
1733	WA	Centralia	3845	BW22		6/30/2025
1734	WA	Centralia	3845	BW22		7/1/2025
1735	WA	Centralia	3845	BW22		7/2/2025
1736	WA	Centralia	3845	BW22		7/3/2025
1737	WA	Centralia	3845	BW22		7/4/2025
1738	WA	Centralia	3845	BW22		7/5/2025
1739	WA	Centralia	3845	BW22		7/6/2025
1740	WA	Centralia	3845	BW22		7/7/2025
1741	WA	Centralia	3845	BW22		7/8/2025
1742	WA	Centralia	3845	BW22		7/9/2025
1743	WA	Centralia	3845	BW22		7/10/2025
1744	WA	Centralia	3845	BW22		7/11/2025
1745	WA	Centralia	3845	BW22		7/12/2025
1746	WA	Centralia	3845	BW22		7/13/2025
1747	WA	Centralia	3845	BW22		7/14/2025
1748	WA	Centralia	3845	BW22		7/15/2025
1749	WA	Centralia	3845	BW22		7/16/2025
1750	WA	Centralia	3845	BW22		7/17/2025
1751	WA	Centralia	3845	BW22		7/18/2025
1752	WA	Centralia	3845	BW22		7/19/2025
1753	WA	Centralia	3845	BW22		7/20/2025
1754	WA	Centralia	3845	BW22		7/21/2025
1755	WA	Centralia	3845	BW22		7/22/2025
1756	WA	Centralia	3845	BW22		7/23/2025
1757	WA	Centralia	3845	BW22		7/24/2025
1758	WA	Centralia	3845	BW22		7/25/2025
1759	WA	Centralia	3845	BW22		7/26/2025
1760	WA	Centralia	3845	BW22		7/27/2025
1761	WA	Centralia	3845	BW22		7/28/2025
1762	WA	Centralia	3845	BW22		7/29/2025
1763	WA	Centralia	3845	BW22		7/30/2025

	A	B	C	D	E	F
1764	WA	Centralia	3845	BW22		7/31/2025
1765	WA	Centralia	3845	BW22		8/1/2025
1766	WA	Centralia	3845	BW22		8/2/2025
1767	WA	Centralia	3845	BW22		8/3/2025
1768	WA	Centralia	3845	BW22		8/4/2025
1769	WA	Centralia	3845	BW22		8/5/2025
1770	WA	Centralia	3845	BW22		8/6/2025
1771	WA	Centralia	3845	BW22		8/7/2025
1772	WA	Centralia	3845	BW22		8/8/2025
1773	WA	Centralia	3845	BW22		8/9/2025
1774	WA	Centralia	3845	BW22		8/10/2025
1775	WA	Centralia	3845	BW22		8/11/2025
1776	WA	Centralia	3845	BW22		8/12/2025
1777	WA	Centralia	3845	BW22		8/13/2025
1778	WA	Centralia	3845	BW22		8/14/2025
1779	WA	Centralia	3845	BW22		8/15/2025
1780	WA	Centralia	3845	BW22		8/16/2025
1781	WA	Centralia	3845	BW22		8/17/2025
1782	WA	Centralia	3845	BW22		8/18/2025
1783	WA	Centralia	3845	BW22		8/19/2025
1784	WA	Centralia	3845	BW22		8/20/2025
1785	WA	Centralia	3845	BW22		8/21/2025
1786	WA	Centralia	3845	BW22		8/22/2025
1787	WA	Centralia	3845	BW22		8/23/2025
1788	WA	Centralia	3845	BW22		8/24/2025
1789	WA	Centralia	3845	BW22		8/25/2025
1790	WA	Centralia	3845	BW22		8/26/2025
1791	WA	Centralia	3845	BW22		8/27/2025
1792	WA	Centralia	3845	BW22		8/28/2025
1793	WA	Centralia	3845	BW22		8/29/2025
1794	WA	Centralia	3845	BW22		8/30/2025
1795	WA	Centralia	3845	BW22		8/31/2025
1796	WA	Centralia	3845	BW22		9/1/2025
1797	WA	Centralia	3845	BW22		9/2/2025
1798	WA	Centralia	3845	BW22		9/3/2025
1799	WA	Centralia	3845	BW22		9/4/2025
1800	WA	Centralia	3845	BW22		9/5/2025
1801	WA	Centralia	3845	BW22		9/6/2025
1802	WA	Centralia	3845	BW22		9/7/2025
1803	WA	Centralia	3845	BW22		9/8/2025
1804	WA	Centralia	3845	BW22		9/9/2025
1805	WA	Centralia	3845	BW22		9/10/2025
1806	WA	Centralia	3845	BW22		9/11/2025

	A	B	C	D	E	F
1807	WA	Centralia	3845	BW22		9/12/2025
1808	WA	Centralia	3845	BW22		9/13/2025
1809	WA	Centralia	3845	BW22		9/14/2025
1810	WA	Centralia	3845	BW22		9/15/2025
1811	WA	Centralia	3845	BW22		9/16/2025
1812	WA	Centralia	3845	BW22		9/17/2025
1813	WA	Centralia	3845	BW22		9/18/2025
1814	WA	Centralia	3845	BW22		9/19/2025
1815	WA	Centralia	3845	BW22		9/20/2025
1816	WA	Centralia	3845	BW22		9/21/2025
1817	WA	Centralia	3845	BW22		9/22/2025
1818	WA	Centralia	3845	BW22		9/23/2025
1819	WA	Centralia	3845	BW22		9/24/2025
1820	WA	Centralia	3845	BW22		9/25/2025
1821	WA	Centralia	3845	BW22		9/26/2025
1822	WA	Centralia	3845	BW22		9/27/2025
1823	WA	Centralia	3845	BW22		9/28/2025
1824	WA	Centralia	3845	BW22		9/29/2025
1825	WA	Centralia	3845	BW22		9/30/2025
1826	WA	Centralia	3845	BW22		10/1/2025
1827	WA	Centralia	3845	BW22		10/2/2025
1828	WA	Centralia	3845	BW22		10/3/2025
1829	WA	Centralia	3845	BW22		10/4/2025
1830	WA	Centralia	3845	BW22		10/5/2025
1831	WA	Centralia	3845	BW22		10/6/2025
1832	WA	Centralia	3845	BW22		10/7/2025
1833	WA	Centralia	3845	BW22		10/8/2025
1834	WA	Centralia	3845	BW22		10/9/2025
1835	WA	Centralia	3845	BW22		10/10/2025
1836	WA	Centralia	3845	BW22		10/11/2025
1837	WA	Centralia	3845	BW22		10/12/2025
1838	WA	Centralia	3845	BW22		10/13/2025
1839	WA	Centralia	3845	BW22		10/14/2025
1840	WA	Centralia	3845	BW22		10/15/2025
1841	WA	Centralia	3845	BW22		10/16/2025
1842	WA	Centralia	3845	BW22		10/17/2025
1843	WA	Centralia	3845	BW22		10/18/2025
1844	WA	Centralia	3845	BW22		10/19/2025
1845	WA	Centralia	3845	BW22		10/20/2025
1846	WA	Centralia	3845	BW22		10/21/2025
1847	WA	Centralia	3845	BW22		10/22/2025
1848	WA	Centralia	3845	BW22		10/23/2025
1849	WA	Centralia	3845	BW22		10/24/2025

	A	B	C	D	E	F
1850	WA	Centralia	3845	BW22		10/25/2025
1851	WA	Centralia	3845	BW22		10/26/2025
1852	WA	Centralia	3845	BW22		10/27/2025
1853	WA	Centralia	3845	BW22		10/28/2025
1854	WA	Centralia	3845	BW22		10/29/2025
1855	WA	Centralia	3845	BW22		10/30/2025
1856	WA	Centralia	3845	BW22		10/31/2025
1857	WA	Centralia	3845	BW22		11/1/2025
1858	WA	Centralia	3845	BW22		11/2/2025
1859	WA	Centralia	3845	BW22		11/3/2025
1860	WA	Centralia	3845	BW22		11/4/2025
1861	WA	Centralia	3845	BW22		11/5/2025
1862	WA	Centralia	3845	BW22		11/6/2025
1863	WA	Centralia	3845	BW22		11/7/2025
1864	WA	Centralia	3845	BW22		11/8/2025
1865	WA	Centralia	3845	BW22		11/9/2025
1866	WA	Centralia	3845	BW22		11/10/2025
1867	WA	Centralia	3845	BW22		11/11/2025
1868	WA	Centralia	3845	BW22		11/12/2025
1869	WA	Centralia	3845	BW22		11/13/2025
1870	WA	Centralia	3845	BW22		11/14/2025
1871	WA	Centralia	3845	BW22		11/15/2025
1872	WA	Centralia	3845	BW22		11/16/2025
1873	WA	Centralia	3845	BW22		11/17/2025
1874	WA	Centralia	3845	BW22		11/18/2025
1875	WA	Centralia	3845	BW22		11/19/2025
1876	WA	Centralia	3845	BW22		11/20/2025
1877	WA	Centralia	3845	BW22		11/21/2025
1878	WA	Centralia	3845	BW22		11/22/2025
1879	WA	Centralia	3845	BW22		11/23/2025
1880	WA	Centralia	3845	BW22		11/24/2025
1881	WA	Centralia	3845	BW22		11/25/2025
1882	WA	Centralia	3845	BW22		11/26/2025
1883	WA	Centralia	3845	BW22		11/27/2025
1884	WA	Centralia	3845	BW22		11/28/2025
1885	WA	Centralia	3845	BW22		11/29/2025
1886	WA	Centralia	3845	BW22		11/30/2025
1887	WA	Centralia	3845	BW22		12/1/2025
1888	WA	Centralia	3845	BW22		12/2/2025
1889	WA	Centralia	3845	BW22		12/3/2025
1890	WA	Centralia	3845	BW22		12/4/2025
1891	WA	Centralia	3845	BW22		12/5/2025
1892	WA	Centralia	3845	BW22		12/6/2025

	A	B	C	D	E	F
1893	WA	Centralia	3845	BW22		12/7/2025
1894	WA	Centralia	3845	BW22		12/8/2025
1895	WA	Centralia	3845	BW22		12/9/2025
1896	WA	Centralia	3845	BW22		12/10/2025
1897	WA	Centralia	3845	BW22		12/11/2025
1898	WA	Centralia	3845	BW22		12/12/2025
1899	WA	Centralia	3845	BW22		12/13/2025
1900	WA	Centralia	3845	BW22		12/14/2025
1901	WA	Centralia	3845	BW22		12/15/2025
1902	WA	Centralia	3845	BW22		12/16/2025
1903	WA	Centralia	3845	BW22		12/17/2025
1904	WA	Centralia	3845	BW22		12/18/2025
1905	WA	Centralia	3845	BW22		12/19/2025
1906	WA	Centralia	3845	BW22		12/20/2025
1907	WA	Centralia	3845	BW22		12/21/2025
1908	WA	Centralia	3845	BW22		12/22/2025
1909	WA	Centralia	3845	BW22		12/23/2025
1910	WA	Centralia	3845	BW22		12/24/2025
1911	WA	Centralia	3845	BW22		12/25/2025
1912	WA	Centralia	3845	BW22		12/26/2025
1913	WA	Centralia	3845	BW22		12/27/2025
1914	WA	Centralia	3845	BW22		12/28/2025
1915	WA	Centralia	3845	BW22		12/29/2025
1916	WA	Centralia	3845	BW22		12/30/2025
1917	WA	Centralia	3845	BW22		12/31/2025

	G	H	I	J
1	Operating Time Count	Sum of the Operating Time	Gross Load (MWh)	Steam Load (1000 lb)
2	0	0		
3	0	0		
4	0	0		
5	0	0		
6	0	0		
7	0	0		
8	0	0		
9	0	0		
10	0	0		
11	0	0		
12	0	0		
13	0	0		
14	0	0		
15	0	0		
16	0	0		
17	0	0		
18	0	0		
19	0	0		
20	0	0		
21	0	0		
22	0	0		
23	0	0		
24	0	0		
25	0	0		
26	0	0		
27	0	0		
28	0	0		
29	0	0		
30	0	0		
31	0	0		
32	0	0		
33	0	0		
34	0	0		
35	0	0		
36	0	0		
37	0	0		
38	0	0		
39	0	0		
40	0	0		
41	0	0		
42	0	0		
43	0	0		

	G	H	I	J
44	0	0		
45	0	0		
46	0	0		
47	0	0		
48	0	0		
49	0	0		
50	0	0		
51	0	0		
52	0	0		
53	0	0		
54	0	0		
55	0	0		
56	0	0		
57	0	0		
58	0	0		
59	0	0		
60	0	0		
61	0	0		
62	0	0		
63	0	0		
64	0	0		
65	0	0		
66	0	0		
67	0	0		
68	0	0		
69	0	0		
70	0	0		
71	0	0		
72	0	0		
73	0	0		
74	0	0		
75	0	0		
76	0	0		
77	0	0		
78	0	0		
79	0	0		
80	0	0		
81	0	0		
82	0	0		
83	0	0		
84	0	0		
85	0	0		
86	0	0		

	G	H	I	J
87	0	0		
88	0	0		
89	0	0		
90	0	0		
91	0	0		
92	24	24	10700	
93	24	24	7649	
94	24	24	8694	
95	24	24	11769	
96	24	24	10567	
97	24	24	11867	
98	24	24	14741	
99	24	24	12528	
100	24	24	12469	
101	24	24	10779	
102	24	24	13921	
103	24	24	13016	
104	24	24	9733	
105	24	24	13306	
106	24	24	9985	
107	24	24	10604	
108	24	24	10094	
109	24	24	12542	
110	24	24	16437	
111	24	24	13966	
112	24	24	14269	
113	24	24	12430	
114	24	24	14992	
115	24	24	14082	
116	24	24	15297	
117	24	24	15967	
118	24	24	15071	
119	24	24	13464	
120	24	24	14695	
121	24	24	9977	
122	24	24	11922	
123	24	24	14961	
124	24	24	11375	
125	24	24	12216	
126	24	24	9743	
127	24	24	9774	
128	24	24	9912	
129	24	24	13285	

	G	H	I	J
130	24	24	14764	
131	24	24	15421	
132	24	24	15461	
133	24	24	15263	
134	24	24	15582	
135	23	22.9	13455.9	
136	0	0		
137	0	0		
138	0	0		
139	0	0		
140	0	0		
141	0	0		
142	0	0		
143	17	16.35	19.35	
144	24	24	8458	
145	24	24	12232	
146	24	24	15667	
147	24	24	12499	
148	24	24	10816	
149	24	24	13110	
150	24	24	12552	
151	24	22.67	11400.24	
152	24	24	15097	
153	24	24	15815	
154	24	24	15778	
155	24	24	14262	
156	24	24	9673	
157	24	24	13554	
158	24	24	15814	
159	24	24	15805	
160	24	24	15836	
161	24	24	15816	
162	24	24	15799	
163	24	24	15505	
164	24	24	15391	
165	24	24	15080	
166	24	24	15291	
167	24	24	14819	
168	24	24	14214	
169	24	24	14044	
170	24	24	9017	
171	24	24	9493	
172	24	24	13387	

	G	H	I	J
173	24	24	13666	
174	24	24	12613	
175	24	24	13141	
176	24	24	10705	
177	24	24	9023	
178	24	24	11149	
179	24	24	13754	
180	24	24	14834	
181	24	24	14819	
182	24	24	14579	
183	24	24	13563	
184	2	1.53	179.4	
185	0	0		
186	0	0		
187	0	0		
188	0	0		
189	0	0		
190	0	0		
191	0	0		
192	0	0		
193	0	0		
194	0	0		
195	0	0		
196	0	0		
197	0	0		
198	0	0		
199	0	0		
200	0	0		
201	0	0		
202	0	0		
203	0	0		
204	0	0		
205	0	0		
206	0	0		
207	0	0		
208	0	0		
209	0	0		
210	0	0		
211	0	0		
212	0	0		
213	0	0		
214	0	0		
215	0	0		

	G	H	I	J
216	0	0		
217	0	0		
218	0	0		
219	0	0		
220	0	0		
221	0	0		
222	0	0		
223	0	0		
224	0	0		
225	0	0		
226	0	0		
227	0	0		
228	0	0		
229	0	0		
230	0	0		
231	0	0		
232	0	0		
233	0	0		
234	0	0		
235	0	0		
236	0	0		
237	0	0		
238	0	0		
239	0	0		
240	0	0		
241	0	0		
242	0	0		
243	0	0		
244	0	0		
245	0	0		
246	0	0		
247	0	0		
248	0	0		
249	0	0		
250	0	0		
251	0	0		
252	0	0		
253	0	0		
254	4	3.13	3.13	
255	11	10.53	10.53	
256	0	0		
257	23	22.5	1964.5	
258	19	18.5	8919	

	G	H	I	J
259	0	0		
260	0	0		
261	0	0		
262	0	0		
263	0	0		
264	0	0		
265	0	0		
266	0	0		
267	0	0		
268	21	20.45	1449.45	
269	24	24	12559	
270	24	24	14265	
271	24	24	16274	
272	24	24	13948	
273	24	24	12077	
274	24	24	11661	
275	24	24	13238	
276	24	24	12484	
277	24	24	14374	
278	24	24	16522	
279	24	24	16408	
280	24	24	16306	
281	24	24	16286	
282	24	24	14051	
283	24	24	12688	
284	24	24	12526	
285	24	24	11954	
286	24	24	13939	
287	24	24	15931	
288	24	24	14665	
289	24	24	15938	
290	24	24	16514	
291	24	24	15788	
292	24	24	14587	
293	24	24	16115	
294	24	24	16452	
295	24	24	16250	
296	24	24	16542	
297	24	24	16548	
298	24	24	16550	
299	24	24	16537	
300	24	24	16517	
301	24	24	16552	

	G	H	I	J
302	24	24	16527	
303	24	24	14715	
304	24	24	14793	
305	24	24	16556	
306	24	24	16567	
307	24	24	16560	
308	24	24	16539	
309	24	24	16233	
310	24	24	15924	
311	24	24	15018	
312	24	24	16568	
313	24	24	16564	
314	24	24	16559	
315	24	24	16385	
316	24	24	16550	
317	24	24	16518	
318	24	24	16342	
319	24	24	16303	
320	24	24	16168	
321	24	24	16552	
322	24	24	16492	
323	24	24	16287	
324	24	24	15540	
325	24	24	11934	
326	24	24	16285	
327	24	24	16523	
328	14	13.13	7945.11	
329	0	0		
330	0	0		
331	16	15.98	5113.98	
332	24	24	16502	
333	24	24	16155	
334	24	24	15858	
335	24	24	16457	
336	24	24	16498	
337	24	24	16507	
338	24	24	16533	
339	24	24	16476	
340	24	24	16072	
341	24	24	16509	
342	24	24	16388	
343	24	24	16585	
344	24	24	16315	

	G	H	I	J
345	24	24	16178	
346	24	24	15738	
347	24	24	16313	
348	24	24	16095	
349	24	24	14664	
350	1	0.42	9.24	
351	0	0		
352	10	9.17	727.77	
353	0	0		
354	0	0		
355	0	0		
356	17	16.6	6505.6	
357	24	24	16561	
358	24	24	16562	
359	24	24	16556	
360	24	24	16302	
361	24	24	16306	
362	24	24	16503	
363	24	24	16485	
364	24	24	16238	
365	24	24	16569	
366	24	24	16570	
367	24	24	16489	
368	24	24	16578	
369	24	24	16560	
370	24	24	16335	
371	20	19.77	13177.88	
372	0	0		
373	21	20.51	7161.51	
374	24	24	12879	
375	24	24	16559	
376	24	24	16560	
377	24	24	16441	
378	24	24	16445	
379	24	24	16563	
380	24	24	15288	
381	24	24	14615	
382	24	24	16446	
383	24	24	16585	
384	24	24	16445	
385	24	24	16294	
386	24	24	16384	
387	24	24	16437	

	G	H	I	J
388	24	24	16453	
389	24	24	16440	
390	24	24	15642	
391	24	24	16008	
392	24	24	16239	
393	24	24	16088	
394	24	24	16596	
395	24	24	16563	
396	24	24	16514	
397	24	24	16532	
398	24	24	16550	
399	24	24	16255	
400	24	24	16585	
401	24	24	16571	
402	24	24	16438	
403	24	24	16574	
404	24	24	15601	
405	24	24	13026	
406	24	24	14378	
407	24	24	16063	
408	24	24	16403	
409	24	24	12371	
410	24	24	15906	
411	24	24	15968	
412	24	24	16439	
413	24	24	15223	
414	2	1.62	80.82	
415	0	0		
416	0	0		
417	0	0		
418	9	8.1	8.1	
419	13	11.92	104.45	
420	0	0		
421	0	0		
422	0	0		
423	0	0		
424	0	0		
425	0	0		
426	0	0		
427	0	0		
428	0	0		
429	0	0		
430	0	0		

	G	H	I	J
431	0	0		
432	0	0		
433	0	0		
434	0	0		
435	0	0		
436	0	0		
437	0	0		
438	0	0		
439	0	0		
440	0	0		
441	0	0		
442	0	0		
443	0	0		
444	0	0		
445	0	0		
446	0	0		
447	6	5.22	5.22	
448	24	24	5909	
449	24	24	8901	
450	24	24	11371	
451	24	24	10358	
452	24	24	16376	
453	24	24	16559	
454	24	24	16005	
455	24	24	16601	
456	24	24	16345	
457	18	17.68	12380.56	
458	0	0		
459	0	0		
460	0	0		
461	0	0		
462	14	12.67	14.55	
463	0	0		
464	1	0.97	0.97	
465	24	24	6911	
466	24	24	15361	
467	24	24	15869	
468	24	24	12966	
469	24	24	16355	
470	24	24	15979	
471	24	24	16511	
472	24	24	16562	
473	24	24	15454	

	G	H	I	J
474	24	24	10489	
475	24	24	16555	
476	24	24	13106	
477	24	24	12691	
478	1	0.72	9.36	
479	2	1.58	1.58	
480	24	24	11079	
481	24	24	15762	
482	24	24	16453	
483	24	24	16530	
484	24	24	16252	
485	24	24	16538	
486	24	24	15326	
487	24	24	13380	
488	24	24	15294	
489	24	24	16575	
490	24	24	16689	
491	24	24	16850	
492	24	24	14765	
493	24	24	15043	
494	24	24	14418	
495	24	24	16228	
496	24	24	15196	
497	24	24	13849	
498	24	24	16626	
499	24	24	16445	
500	24	24	13738	
501	24	24	12933	
502	24	24	10375	
503	24	24	11968	
504	24	24	10718	
505	24	24	13772	
506	24	24	10188	
507	24	24	9911	
508	24	24	15353	
509	20	19.8	13141.4	
510	0	0		
511	20	19.03	2895.53	
512	24	24	15128	
513	24	24	15843	
514	22	20.87	13564.87	
515	24	24	9864	
516	24	24	14249	

	G	H	I	J
517	24	24	16353	
518	24	24	14325	
519	24	24	16152	
520	24	24	16213	
521	24	24	15171	
522	24	24	14569	
523	24	24	12651	
524	24	24	14144	
525	24	24	14782	
526	24	24	13730	
527	24	24	11266	
528	24	24	11618	
529	24	24	15212	
530	24	24	13286	
531	24	24	12729	
532	24	24	15790	
533	24	24	16316	
534	24	24	13891	
535	24	24	11143	
536	24	24	16511	
537	24	24	16126	
538	24	24	13882	
539	24	24	15094	
540	24	23.07	14143.68	
541	0	0		
542	19	18.7	6315.7	
543	24	24	14905	
544	24	24	15518	
545	24	24	13789	
546	24	24	15067	
547	24	24	14770	
548	24	24	11877	
549	21	19.7	6722.66	
550	24	24	10357	
551	24	24	13760	
552	24	24	13184	
553	24	24	11180	
554	24	24	10276	
555	24	24	10280	
556	24	24	10731	
557	24	24	11755	
558	24	24	14697	
559	24	24	16207	

	G	H	I	J
560	24	24	15461	
561	24	24	15930	
562	24	24	14543	
563	24	24	13656	
564	24	24	15403	
565	24	24	15577	
566	24	24	15830	
567	24	24	15696	
568	24	24	15991	
569	24	24	15487	
570	3	2.5	579	
571	0	0		
572	0	0		
573	0	0		
574	0	0		
575	0	0		
576	0	0		
577	0	0		
578	0	0		
579	0	0		
580	0	0		
581	0	0		
582	0	0		
583	0	0		
584	0	0		
585	0	0		
586	0	0		
587	0	0		
588	0	0		
589	0	0		
590	0	0		
591	0	0		
592	0	0		
593	0	0		
594	0	0		
595	0	0		
596	0	0		
597	0	0		
598	0	0		
599	0	0		
600	0	0		
601	0	0		
602	0	0		

	G	H	I	J
603	0	0		
604	0	0		
605	0	0		
606	0	0		
607	0	0		
608	0	0		
609	0	0		
610	0	0		
611	0	0		
612	0	0		
613	0	0		
614	0	0		
615	0	0		
616	0	0		
617	0	0		
618	0	0		
619	0	0		
620	0	0		
621	0	0		
622	0	0		
623	0	0		
624	0	0		
625	0	0		
626	0	0		
627	0	0		
628	0	0		
629	0	0		
630	0	0		
631	0	0		
632	0	0		
633	0	0		
634	0	0		
635	0	0		
636	0	0		
637	0	0		
638	0	0		
639	0	0		
640	0	0		
641	0	0		
642	0	0		
643	0	0		
644	0	0		
645	0	0		

	G	H	I	J
646	6	5.7	5.7	
647	24	24	1393	
648	24	24	10332	
649	24	24	13149	
650	24	24	11841	
651	24	24	12977	
652	24	24	11110	
653	24	24	10567	
654	24	24	8795	
655	24	24	13869	
656	24	24	16844	
657	24	24	16180	
658	24	24	15946	
659	24	24	14372	
660	24	24	15924	
661	24	24	16742	
662	24	24	17008	
663	24	24	16865	
664	24	24	16886	
665	24	24	16760	
666	24	24	16548	
667	24	24	16063	
668	24	24	16440	
669	24	24	16713	
670	24	24	16461	
671	24	24	16493	
672	24	24	16441	
673	24	24	16895	
674	24	24	17009	
675	24	24	16897	
676	24	24	15691	
677	24	24	16925	
678	24	24	16850	
679	24	24	16379	
680	24	24	16112	
681	24	24	15968	
682	24	24	16373	
683	24	24	16712	
684	24	24	16661	
685	24	24	14744	
686	23	22.75	10692.5	
687	0	0		
688	3	2.75	2.75	

	G	H	I	J
689	24	24	11588	
690	24	24	15346	
691	24	24	17048	
692	24	24	16986	
693	24	24	16987	
694	23	22.12	12746.12	
695	10	7.34	452.92	
696	22	20.7	5840.7	
697	24	24	15354	
698	24	24	16967	
699	24	24	17043	
700	24	24	17029	
701	24	24	17016	
702	24	24	16978	
703	24	24	16995	
704	24	24	16970	
705	24	24	16865	
706	24	24	16153	
707	24	24	17006	
708	24	24	16985	
709	24	24	17005	
710	24	24	17026	
711	24	24	16885	
712	24	24	16581	
713	24	24	16301	
714	24	24	16070	
715	24	24	16569	
716	24	24	16811	
717	24	24	16893	
718	24	24	17030	
719	24	24	16835	
720	24	24	16895	
721	24	24	16236	
722	24	24	16908	
723	24	24	17020	
724	24	24	17008	
725	24	24	17032	
726	24	24	16975	
727	24	24	16747	
728	24	24	15801	
729	24	24	16829	
730	24	24	16634	
731	24	24	16842	

	G	H	I	J
732	24	24	16973	
733	24	24	16988	
734	24	24	16980	
735	24	24	17003	
736	24	24	16967	
737	24	24	17027	
738	24	24	17002	
739	24	24	16785	
740	24	24	16760	
741	24	24	17015	
742	24	24	16901	
743	24	24	16954	
744	24	24	16875	
745	24	24	16920	
746	24	24	16934	
747	24	24	16969	
748	24	24	17017	
749	24	24	16632	
750	24	24	16454	
751	24	24	16889	
752	24	24	16908	
753	24	24	16619	
754	24	24	16409	
755	24	24	16184	
756	24	24	16742	
757	24	24	16842	
758	24	24	17022	
759	24	24	14961	
760	24	24	16361	
761	24	24	16818	
762	24	24	16643	
763	24	24	16848	
764	24	24	15744	
765	24	24	15315	
766	24	24	15956	
767	24	24	16003	
768	24	24	16608	
769	24	24	16444	
770	24	24	16913	
771	20	19.35	12440.25	
772	0	0		
773	0	0		
774	0	0		

	G	H	I	J
775	0	0		
776	0	0		
777	0	0		
778	0	0		
779	7	6.5	6.5	
780	24	24	5004	
781	24	24	17047	
782	24	24	16659	
783	24	24	16702	
784	24	24	17027	
785	24	23.55	15036.6	
786	0	0		
787	0	0		
788	0	0		
789	0	0		
790	0	0		
791	0	0		
792	19	18.85	923.85	
793	24	24	15650	
794	24	24	16612	
795	24	24	17078	
796	24	24	17014	
797	16	15.68	9656.44	
798	0	0		
799	0	0		
800	0	0		
801	16	15.8	1059.8	
802	24	24	15752	
803	24	24	17025	
804	24	24	17038	
805	24	24	17046	
806	24	24	17050	
807	24	24	16954	
808	24	24	17052	
809	24	24	16929	
810	24	24	16760	
811	24	24	16872	
812	24	24	17054	
813	24	24	17055	
814	24	24	16860	
815	24	24	16412	
816	24	24	16160	
817	24	24	15462	

	G	H	I	J
818	2	1.93	357.03	
819	0	0		
820	0	0		
821	16	15.78	4533.78	
822	24	24	16493	
823	24	24	16557	
824	24	24	16538	
825	24	24	16553	
826	24	24	16523	
827	24	24	16555	
828	23	22.88	14408.52	
829	0	0		
830	5	4.63	4.63	
831	24	24	13947	
832	24	24	16536	
833	24	24	16546	
834	24	24	16553	
835	24	24	16051	
836	24	24	16129	
837	24	24	16279	
838	24	24	16464	
839	24	24	16238	
840	24	24	16203	
841	24	24	16611	
842	24	24	16571	
843	24	24	16514	
844	24	24	16541	
845	24	24	16526	
846	24	24	16552	
847	24	24	16485	
848	24	24	16528	
849	24	24	16556	
850	24	24	16576	
851	24	24	16536	
852	24	24	16532	
853	24	24	16525	
854	24	24	16660	
855	24	24	16612	
856	24	24	16521	
857	24	24	16197	
858	24	24	15750	
859	24	24	16134	
860	24	24	16089	

	G	H	I	J
861	24	24	16458	
862	24	24	16500	
863	24	24	16449	
864	24	24	16533	
865	24	24	16536	
866	24	24	16521	
867	24	24	16538	
868	24	24	16544	
869	24	24	16397	
870	24	24	16171	
871	24	24	14721	
872	24	24	16292	
873	24	24	16431	
874	24	24	16540	
875	24	24	16227	
876	24	24	16564	
877	24	24	16562	
878	24	24	16561	
879	24	24	16471	
880	24	24	16561	
881	24	24	16560	
882	24	24	16550	
883	24	24	16552	
884	24	24	16549	
885	24	24	16554	
886	24	24	16516	
887	24	24	16572	
888	24	24	16561	
889	24	24	16557	
890	24	24	16547	
891	24	24	16553	
892	24	24	16504	
893	24	24	16274	
894	24	24	16461	
895	24	24	16546	
896	24	24	16167	
897	24	24	16049	
898	24	24	16181	
899	24	24	16363	
900	24	24	16274	
901	24	24	16359	
902	24	24	16064	
903	23	22.6	13497.6	

	G	H	I	J
904	0	0		
905	10	9.52	1842.52	
906	6	5.42	1602.78	
907	22	21	9700	
908	24	24	16532	
909	24	24	16372	
910	24	24	16432	
911	24	24	16472	
912	24	24	15811	
913	24	24	16105	
914	24	24	16467	
915	24	24	16528	
916	24	24	16467	
917	24	24	16512	
918	24	24	15857	
919	24	24	15226	
920	24	24	15604	
921	24	24	16244	
922	24	24	16154	
923	24	24	16327	
924	24	24	16141	
925	24	24	16227	
926	24	24	16276	
927	24	24	15586	
928	24	24	16216	
929	24	24	16227	
930	24	24	16406	
931	24	24	16478	
932	24	24	16071	
933	24	24	16044	
934	24	24	16069	
935	24	24	15911	
936	24	24	16052	
937	24	24	16198	
938	24	24	16042	
939	24	24	15738	
940	24	24	12904	
941	24	24	6895	
942	24	24	7737	
943	24	24	7086	
944	19	18.37	7521.27	
945	0	0		
946	0	0		

	G	H	I	J
947	0	0		
948	0	0		
949	0	0		
950	0	0		
951	0	0		
952	0	0		
953	0	0		
954	0	0		
955	0	0		
956	0	0		
957	0	0		
958	0	0		
959	0	0		
960	0	0		
961	0	0		
962	0	0		
963	0	0		
964	0	0		
965	0	0		
966	0	0		
967	0	0		
968	0	0		
969	0	0		
970	0	0		
971	0	0		
972	0	0		
973	0	0		
974	0	0		
975	0	0		
976	0	0		
977	0	0		
978	0	0		
979	0	0		
980	0	0		
981	0	0		
982	17	16.3	275.3	
983	24	24	6837	
984	24	24	8033	
985	24	24	7304	
986	24	24	7011	
987	24	24	8701	
988	24	24	8775	
989	24	24	7494	

	G	H	I	J
990	24	24	7078	
991	24	24	7017	
992	24	24	7819	
993	24	24	9070	
994	24	24	8814	
995	24	24	8786	
996	24	24	8279	
997	24	24	8032	
998	24	24	8051	
999	24	24	8443	
1000	24	24	8661	
1001	24	24	8576	
1002	22	21.07	7276.11	
1003	0	0		
1004	0	0		
1005	0	0		
1006	0	0		
1007	0	0		
1008	0	0		
1009	7	6.5	6.5	
1010	24	24	7585	
1011	24	24	12303	
1012	24	24	10734	
1013	24	24	14080	
1014	24	24	15529	
1015	24	24	14021	
1016	24	24	16468	
1017	24	24	16426	
1018	24	24	16459	
1019	24	24	16535	
1020	24	24	16511	
1021	24	24	16202	
1022	24	24	16449	
1023	24	24	16438	
1024	24	24	16197	
1025	24	24	15981	
1026	24	24	16310	
1027	24	24	16085	
1028	24	24	16245	
1029	24	24	16264	
1030	24	24	15456	
1031	24	24	16136	
1032	24	24	15938	

	G	H	I	J
1033	24	24	16220	
1034	24	24	16171	
1035	24	24	16096	
1036	24	24	16068	
1037	24	24	16159	
1038	24	24	16076	
1039	24	24	16153	
1040	24	24	16130	
1041	24	24	15695	
1042	24	24	16167	
1043	24	24	16133	
1044	24	24	16161	
1045	24	24	16185	
1046	24	24	15950	
1047	24	24	15856	
1048	24	24	15798	
1049	24	24	15916	
1050	24	24	15900	
1051	24	24	13128	
1052	24	24	15047	
1053	24	24	15235	
1054	24	24	14280	
1055	24	24	13906	
1056	24	24	14898	
1057	24	24	16143	
1058	24	24	16006	
1059	24	24	16040	
1060	24	24	16021	
1061	24	24	16030	
1062	24	24	15635	
1063	24	24	14340	
1064	24	24	16005	
1065	24	24	13768	
1066	24	24	10872	
1067	24	24	8136	
1068	24	24	7159	
1069	24	24	13295	
1070	24	24	16044	
1071	24	24	15696	
1072	24	24	15899	
1073	24	24	15291	
1074	24	24	15824	
1075	24	24	15426	

	G	H	I	J
1076	24	24	15278	
1077	24	24	16172	
1078	24	24	16065	
1079	24	24	16048	
1080	24	24	16165	
1081	24	24	15816	
1082	24	24	15868	
1083	24	24	15876	
1084	24	24	15992	
1085	13	12.55	7133.6	
1086	0	0		
1087	0	0		
1088	8	5.95	5.95	
1089	24	24	10278	
1090	24	24	16065	
1091	24	24	15446	
1092	24	24	14889	
1093	24	24	15055	
1094	24	24	16042	
1095	24	24	15576	
1096	24	24	15598	
1097	24	24	15876	
1098	24	24	15986	
1099	24	24	15788	
1100	24	24	16006	
1101	24	24	15980	
1102	24	24	15976	
1103	24	24	15881	
1104	24	24	15989	
1105	24	24	15886	
1106	24	24	15988	
1107	24	24	15987	
1108	24	24	15948	
1109	24	24	15462	
1110	24	24	15989	
1111	24	24	16087	
1112	24	24	16086	
1113	24	24	16089	
1114	24	24	16079	
1115	24	24	15986	
1116	24	24	15363	
1117	24	24	12924	
1118	24	24	15352	

	G	H	I	J
1119	24	24	16104	
1120	24	24	16237	
1121	24	24	16231	
1122	24	24	16338	
1123	24	24	16357	
1124	24	24	15343	
1125	24	24	16293	
1126	24	24	16246	
1127	24	24	15850	
1128	24	24	15755	
1129	24	24	14839	
1130	24	24	13878	
1131	24	24	15424	
1132	24	24	13913	
1133	24	24	15580	
1134	24	24	16132	
1135	24	24	14655	
1136	23	22.58	7247.06	
1137	0	0		
1138	0	0		
1139	0	0		
1140	23	22.43	8287.43	
1141	24	24	16149	
1142	24	24	15937	
1143	24	24	15924	
1144	24	24	15012	
1145	24	24	15955	
1146	24	24	13795	
1147	24	24	12006	
1148	7	6.97	1981.15	
1149	0	0		
1150	0	0		
1151	0	0		
1152	0	0		
1153	0	0		
1154	0	0		
1155	1	0.92	0.92	
1156	24	24	4503	
1157	24	24	15709	
1158	24	24	15909	
1159	24	24	15932	
1160	24	24	15503	
1161	24	24	15605	

	G	H	I	J
1162	24	24	15587	
1163	24	24	15914	
1164	24	24	11080	
1165	24	24	15237	
1166	24	24	15960	
1167	24	24	16007	
1168	24	24	15984	
1169	24	24	15986	
1170	24	24	15900	
1171	24	24	16021	
1172	24	24	16052	
1173	24	24	15994	
1174	24	24	15719	
1175	24	24	15989	
1176	24	24	15932	
1177	24	24	15663	
1178	24	24	14526	
1179	24	24	15860	
1180	24	24	13873	
1181	24	24	12006	
1182	14	13.9	6676.2	
1183	0	0		
1184	0	0		
1185	0	0		
1186	0	0		
1187	0	0		
1188	0	0		
1189	0	0		
1190	0	0		
1191	0	0		
1192	0	0		
1193	0	0		
1194	0	0		
1195	0	0		
1196	1	0.8	0.8	
1197	24	23.29	3237.93	
1198	24	24	15212	
1199	24	24	15589	
1200	24	24	16500	
1201	24	24	16450	
1202	24	24	16502	
1203	24	24	16124	
1204	24	24	15977	

	G	H	I	J
1205	24	24	15958	
1206	24	24	16222	
1207	24	24	15843	
1208	24	24	15771	
1209	24	24	15652	
1210	24	24	15972	
1211	24	24	15938	
1212	24	24	16013	
1213	24	24	15771	
1214	24	24	13921	
1215	24	24	12721	
1216	24	24	14144	
1217	24	24	15186	
1218	24	24	14409	
1219	24	24	15604	
1220	24	24	13528	
1221	24	24	15712	
1222	24	24	15806	
1223	24	24	15866	
1224	24	24	15862	
1225	24	24	15318	
1226	24	24	15649	
1227	24	24	15854	
1228	24	24	15912	
1229	24	24	14692	
1230	24	24	15989	
1231	24	24	15886	
1232	24	24	15889	
1233	13	12.78	8257.58	
1234	0	0		
1235	0	0		
1236	13	11.93	1522.93	
1237	24	24	15644	
1238	24	24	15711	
1239	24	24	14811	
1240	24	24	15839	
1241	24	24	7229	
1242	24	24	7050	
1243	24	24	8576	
1244	10	9.35	3348.95	
1245	0	0		
1246	0	0		
1247	0	0		

	G	H	I	J
1248	15	14.33	1070.33	
1249	24	24	11210	
1250	24	24	15987	
1251	24	24	16071	
1252	24	24	16036	
1253	24	24	15971	
1254	24	24	15853	
1255	24	24	14325	
1256	24	24	9924	
1257	24	24	13823	
1258	24	24	8634	
1259	24	24	13786	
1260	24	24	13783	
1261	24	24	12483	
1262	24	24	10067	
1263	24	24	9207	
1264	24	24	9717	
1265	23	22.28	9145.28	
1266	0	0		
1267	0	0		
1268	0	0		
1269	0	0		
1270	0	0		
1271	0	0		
1272	0	0		
1273	0	0		
1274	0	0		
1275	0	0		
1276	0	0		
1277	0	0		
1278	0	0		
1279	0	0		
1280	0	0		
1281	0	0		
1282	0	0		
1283	0	0		
1284	0	0		
1285	0	0		
1286	0	0		
1287	0	0		
1288	0	0		
1289	0	0		
1290	0	0		

	G	H	I	J
1291	0	0		
1292	0	0		
1293	0	0		
1294	0	0		
1295	0	0		
1296	0	0		
1297	0	0		
1298	0	0		
1299	0	0		
1300	0	0		
1301	0	0		
1302	0	0		
1303	0	0		
1304	0	0		
1305	0	0		
1306	0	0		
1307	0	0		
1308	0	0		
1309	0	0		
1310	0	0		
1311	0	0		
1312	0	0		
1313	0	0		
1314	0	0		
1315	0	0		
1316	0	0		
1317	0	0		
1318	0	0		
1319	0	0		
1320	0	0		
1321	0	0		
1322	0	0		
1323	0	0		
1324	0	0		
1325	0	0		
1326	0	0		
1327	0	0		
1328	0	0		
1329	0	0		
1330	0	0		
1331	0	0		
1332	0	0		
1333	0	0		

	G	H	I	J
1334	0	0		
1335	0	0		
1336	0	0		
1337	0	0		
1338	0	0		
1339	0	0		
1340	0	0		
1341	0	0		
1342	0	0		
1343	0	0		
1344	0	0		
1345	0	0		
1346	0	0		
1347	0	0		
1348	0	0		
1349	0	0		
1350	0	0		
1351	0	0		
1352	0	0		
1353	0	0		
1354	0	0		
1355	0	0		
1356	0	0		
1357	0	0		
1358	0	0		
1359	0	0		
1360	0	0		
1361	4	3.98	3.98	
1362	9	7.27	7.27	
1363	17	16.6	1921.8	
1364	0	0		
1365	0	0		
1366	0	0		
1367	0	0		
1368	1	0.1	0.1	
1369	24	24	3933	
1370	18	17.5	7565	
1371	0	0		
1372	9	8.85	102.85	
1373	24	24	8835	
1374	24	24	11988	
1375	24	24	10512	
1376	24	24	11415	

	G	H	I	J
1377	24	24	15195	
1378	24	24	16512	
1379	24	24	16494	
1380	24	24	16415	
1381	24	24	15915	
1382	24	24	12037	
1383	24	24	11589	
1384	24	24	12615	
1385	24	24	16446	
1386	24	24	16378	
1387	24	24	15418	
1388	24	24	16482	
1389	24	24	15794	
1390	24	24	14393	
1391	24	24	15857	
1392	24	24	14840	
1393	24	24	10958	
1394	24	24	13452	
1395	24	24	10979	
1396	24	24	8043	
1397	24	24	11470	
1398	24	24	11887	
1399	24	24	15107	
1400	24	24	16118	
1401	24	24	15986	
1402	24	24	13079	
1403	24	24	13802	
1404	24	24	16021	
1405	24	24	13502	
1406	24	24	16100	
1407	24	24	15793	
1408	24	24	16423	
1409	24	24	15248	
1410	24	24	10821	
1411	24	24	12423	
1412	24	24	8149	
1413	24	24	11120	
1414	24	23.62	7993.42	
1415	24	24	13677	
1416	24	24	14479	
1417	24	24	10067	
1418	24	24	13262	
1419	24	24	11413	

	G	H	I	J
1420	24	24	12181	
1421	24	24	13194	
1422	24	24	8014	
1423	24	24	8091	
1424	24	24	8247	
1425	24	24	11180	
1426	24	24	8015	
1427	24	24	9064	
1428	24	24	12716	
1429	24	24	12836	
1430	24	24	12069	
1431	24	24	9574	
1432	24	24	8792	
1433	24	24	13808	
1434	24	24	16029	
1435	24	24	16295	
1436	24	24	15857	
1437	24	24	15360	
1438	24	24	14557	
1439	24	24	13183	
1440	24	24	12514	
1441	24	24	11386	
1442	24	24	8125	
1443	24	24	10086	
1444	24	24	9539	
1445	24	24	8106	
1446	24	23.72	12054.8	
1447	0	0		
1448	0	0		
1449	0	0		
1450	0	0		
1451	0	0		
1452	5	4.05	4.05	
1453	14	13.52	280.52	
1454	24	24	13108	
1455	24	24	14817	
1456	24	24	14370	
1457	24	24	14759	
1458	24	24	16011	
1459	24	24	9975	
1460	24	24	16452	
1461	24	24	15733	
1462	24	24	15277	

	G	H	I	J
1463	24	24	16110	
1464	24	24	14894	
1465	24	24	14709	
1466	24	24	16466	
1467	24	24	16045	
1468	24	24	15480	
1469	24	24	15837	
1470	24	24	16378	
1471	24	24	16530	
1472	24	24	16470	
1473	24	24	15754	
1474	24	24	15571	
1475	24	24	15014	
1476	24	24	14102	
1477	24	24	14688	
1478	24	24	14480	
1479	24	24	8806	
1480	24	24	9145	
1481	24	24	13687	
1482	11	10.43	4977.24	
1483	0	0		
1484	4	3.58	3.58	
1485	24	24	12593	
1486	24	24	14271	
1487	24	24	8700	
1488	24	24	14075	
1489	24	24	14404	
1490	24	24	16448	
1491	24	24	13360	
1492	24	24	9876	
1493	24	24	8030	
1494	24	24	8027	
1495	24	24	8642	
1496	24	24	11174	
1497	24	24	16136	
1498	24	24	15971	
1499	24	24	13380	
1500	24	24	9419	
1501	24	24	8168	
1502	24	24	8897	
1503	24	24	8735	
1504	24	24	9134	
1505	24	24	11037	

	G	H	I	J
1506	24	24	13302	
1507	24	24	10241	
1508	24	24	8647	
1509	24	24	11139	
1510	24	24	15283	
1511	24	24	12832	
1512	24	24	16313	
1513	24	24	16537	
1514	24	24	15632	
1515	24	24	15597	
1516	24	24	16535	
1517	24	24	16548	
1518	24	24	15299	
1519	24	24	16031	
1520	24	24	15728	
1521	24	24	16004	
1522	24	24	16406	
1523	24	24	16556	
1524	24	24	12787	
1525	2	1.75	323.25	
1526	2	0.72	0.72	
1527	0	0		
1528	0	0		
1529	9	8.23	8.23	
1530	24	24	8818	
1531	24	24	16143	
1532	24	24	16531	
1533	24	24	16509	
1534	24	24	16449	
1535	24	24	15478	
1536	24	24	12485	
1537	24	24	16574	
1538	24	24	15666	
1539	24	24	8721	
1540	24	24	15045	
1541	24	24	14898	
1542	24	24	13916	
1543	24	24	13967	
1544	24	24	13065	
1545	24	24	9185	
1546	24	24	8047	
1547	24	24	8063	
1548	24	24	8083	

	G	H	I	J
1549	24	24	8033	
1550	24	24	8001	
1551	24	24	8094	
1552	24	24	14662	
1553	24	24	10947	
1554	24	24	15293	
1555	24	24	15778	
1556	24	24	15121	
1557	24	24	13484	
1558	24	24	16066	
1559	24	24	16119	
1560	24	24	15048	
1561	24	24	14496	
1562	2	1.7	279.2	
1563	14	13.03	2586.03	
1564	24	24	13556	
1565	24	24	15941	
1566	24	24	16327	
1567	24	24	16363	
1568	24	24	16192	
1569	24	24	16418	
1570	24	24	16415	
1571	24	24	16550	
1572	24	24	16521	
1573	24	24	16517	
1574	24	24	16480	
1575	24	24	16203	
1576	24	24	16530	
1577	24	24	16539	
1578	24	24	16569	
1579	24	24	16481	
1580	24	24	16537	
1581	24	24	16545	
1582	24	24	16566	
1583	24	24	16147	
1584	24	24	15593	
1585	24	24	16168	
1586	24	24	16316	
1587	24	24	16441	
1588	24	24	16434	
1589	24	24	16555	
1590	24	24	16295	
1591	24	24	15861	

	G	H	I	J
1592	24	24	15617	
1593	24	24	16015	
1594	24	24	16416	
1595	24	24	16080	
1596	24	24	16086	
1597	24	24	15933	
1598	24	24	15047	
1599	24	24	15485	
1600	24	24	16080	
1601	24	24	16177	
1602	24	24	15926	
1603	24	24	14571	
1604	24	24	15443	
1605	24	24	10231	
1606	24	24	9635	
1607	24	24	10351	
1608	1	0.05	3.2	
1609	0	0		
1610	0	0		
1611	0	0		
1612	0	0		
1613	0	0		
1614	9	8.15	8.15	
1615	24	24	8621	
1616	24	24	15855	
1617	24	24	16184	
1618	24	24	14762	
1619	24	24	13491	
1620	24	24	9357	
1621	24	24	14490	
1622	24	24	16414	
1623	24	24	16371	
1624	24	24	14634	
1625	24	24	16435	
1626	24	24	12059	
1627	24	24	10685	
1628	24	24	15317	
1629	24	24	15186	
1630	24	24	16157	
1631	24	24	11666	
1632	24	24	10127	
1633	24	24	8168	
1634	24	24	8145	

	G	H	I	J
1635	24	24	8355	
1636	24	24	11238	
1637	23	22.47	6311.5	
1638	0	0		
1639	0	0		
1640	0	0		
1641	0	0		
1642	0	0		
1643	0	0		
1644	0	0		
1645	0	0		
1646	0	0		
1647	0	0		
1648	0	0		
1649	0	0		
1650	0	0		
1651	0	0		
1652	0	0		
1653	0	0		
1654	0	0		
1655	0	0		
1656	0	0		
1657	0	0		
1658	0	0		
1659	0	0		
1660	0	0		
1661	0	0		
1662	0	0		
1663	0	0		
1664	0	0		
1665	0	0		
1666	0	0		
1667	0	0		
1668	0	0		
1669	0	0		
1670	0	0		
1671	0	0		
1672	0	0		
1673	0	0		
1674	0	0		
1675	0	0		
1676	0	0		
1677	0	0		

	G	H	I	J
1678	0	0		
1679	0	0		
1680	0	0		
1681	0	0		
1682	0	0		
1683	0	0		
1684	0	0		
1685	0	0		
1686	0	0		
1687	0	0		
1688	0	0		
1689	0	0		
1690	0	0		
1691	0	0		
1692	0	0		
1693	0	0		
1694	0	0		
1695	0	0		
1696	0	0		
1697	0	0		
1698	0	0		
1699	0	0		
1700	0	0		
1701	0	0		
1702	0	0		
1703	0	0		
1704	0	0		
1705	0	0		
1706	0	0		
1707	0	0		
1708	17	16.03	16.03	
1709	24	24	9893	
1710	24	24	10808	
1711	18	17.72	10025	
1712	0	0		
1713	0	0		
1714	19	18.81	3781.81	
1715	24	24	8591	
1716	24	24	8447	
1717	24	24	8253	
1718	24	24	10526	
1719	24	24	12617	
1720	24	24	11481	

	G	H	I	J
1721	24	24	13697	
1722	24	24	15614	
1723	24	24	8145	
1724	24	24	8042	
1725	24	24	8413	
1726	24	24	15141	
1727	24	24	16202	
1728	24	24	12607	
1729	24	24	14105	
1730	24	24	13443	
1731	24	24	12948	
1732	24	24	14694	
1733	24	24	15972	
1734	24	24	15189	
1735	24	24	8582	
1736	24	24	12951	
1737	24	24	11570	
1738	24	24	12948	
1739	24	24	14228	
1740	24	24	16068	
1741	24	24	15829	
1742	24	24	15701	
1743	24	24	15798	
1744	24	24	15767	
1745	24	24	15600	
1746	24	24	15702	
1747	24	24	14316	
1748	24	24	15989	
1749	24	24	15873	
1750	24	24	15776	
1751	24	24	15041	
1752	24	24	11430	
1753	24	24	13461	
1754	24	24	15781	
1755	24	24	15985	
1756	24	24	15922	
1757	23	22.85	13950.45	
1758	0	0		
1759	0	0		
1760	0	0		
1761	1	0.65	0.65	
1762	24	24	5079	
1763	24	24	16124	

	G	H	I	J
1764	24	24	15953	
1765	24	24	14561	
1766	24	24	11886	
1767	24	24	8768	
1768	24	24	10779	
1769	24	24	13336	
1770	24	24	11630	
1771	24	24	10028	
1772	24	24	12477	
1773	24	24	12820	
1774	14	13.52	6385.68	
1775	0	0		
1776	12	10.2	1059.3	
1777	0	0		
1778	0	0		
1779	0	0		
1780	4	2.31	2.31	
1781	4	3.95	3.95	
1782	24	24	8316	
1783	24	24	15821	
1784	24	24	16053	
1785	24	24	16411	
1786	24	24	16013	
1787	24	24	16031	
1788	24	24	15654	
1789	24	24	16038	
1790	24	22.7	11590.6	
1791	24	24	16173	
1792	24	24	16049	
1793	24	24	15638	
1794	24	24	13815	
1795	24	24	9991	
1796	24	24	13240	
1797	24	24	16061	
1798	24	24	15988	
1799	24	24	15953	
1800	24	24	16052	
1801	24	24	15935	
1802	24	24	13657	
1803	6	5.18	2842	
1804	0	0		
1805	0	0		
1806	0	0		

	G	H	I	J
1807	17	15.75	266.75	
1808	24	24	11015	
1809	24	24	8552	
1810	24	24	15043	
1811	24	24	16098	
1812	24	24	15049	
1813	24	24	13788	
1814	24	24	15984	
1815	24	24	13926	
1816	24	24	9350	
1817	24	24	15809	
1818	24	24	16322	
1819	24	24	16333	
1820	24	24	14699	
1821	24	24	14719	
1822	24	24	16032	
1823	24	24	15495	
1824	24	24	14053	
1825	24	24	14211	
1826	24	24	14028	
1827	24	24	15549	
1828	24	24	14711	
1829	24	24	14501	
1830	24	24	13593	
1831	24	24	15908	
1832	24	24	15986	
1833	24	24	16040	
1834	24	24	15900	
1835	24	24	15430	
1836	24	24	8771	
1837	24	24	11642	
1838	24	24	15796	
1839	24	24	15892	
1840	24	24	16049	
1841	24	24	15454	
1842	24	24	12173	
1843	24	24	15822	
1844	24	24	9548	
1845	24	24	12799	
1846	24	24	15673	
1847	24	24	15941	
1848	24	24	16084	
1849	24	24	15119	

	G	H	I	J
1850	24	24	13679	
1851	24	24	12821	
1852	24	24	14632	
1853	24	24	15626	
1854	24	24	14577	
1855	24	24	15739	
1856	24	24	15846	
1857	24	24	9681	
1858	24	24	9981	
1859	24	24	14897	
1860	24	24	15929	
1861	24	24	15070	
1862	24	24	14134	
1863	24	24	11904	
1864	24	24	15949	
1865	24	24	14016	
1866	24	24	15680	
1867	24	24	16063	
1868	24	24	16076	
1869	24	24	14550	
1870	24	24	14422	
1871	24	24	15697	
1872	24	24	15863	
1873	24	24	15615	
1874	24	24	15103	
1875	24	24	9125	
1876	24	24	15649	
1877	24	24	15855	
1878	24	24	15852	
1879	24	24	15390	
1880	24	24	15497	
1881	24	24	15801	
1882	24	24	15600	
1883	24	24	15874	
1884	24	24	8337	
1885	11	10.67	3341.31	
1886	0	0		
1887	0	0		
1888	0	0		
1889	0	0		
1890	0	0		
1891	0	0		
1892	0	0		

	G	H	I	J
1893	3	2.9	2.9	
1894	24	23.17	1037.07	
1895	24	24	11303	
1896	24	24	8531	
1897	24	24	11587	
1898	24	24	8615	
1899	24	24	9423	
1900	24	24	8593	
1901	24	24	8544	
1902	24	24	8056	
1903	24	24	8495	
1904	24	24	8733	
1905	1	0.33	13.53	
1906	0	0		
1907	0	0		
1908	0	0		
1909	0	0		
1910	0	0		
1911	0	0		
1912	0	0		
1913	0	0		
1914	0	0		
1915	0	0		
1916	0	0		
1917	0	0		

	K	L	M	N
1	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				

	K	L	M	N
44				
45				
46				
47				
48				
49				
50				
51				
52				
53				
54				
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68				
69				
70				
71				
72				
73				
74				
75				
76				
77				
78				
79				
80				
81				
82				
83				
84				
85				
86				

	K	L	M	N
87				
88				
89				
90				
91				
92	0.869	0.0127	12362.9	0.105
93	0.152	0.0035	9119.2	0.105
94	0.273	0.0052	10182.6	0.105
95	1.558	0.0205	13606.1	0.105
96	0.607	0.0087	12221.9	0.105
97	0.846	0.0114	13705.2	0.105
98	3.78	0.0455	16807.2	0.105
99	1.923	0.0266	14269.1	0.105
100	1.895	0.0266	14090.6	0.105
101	1.56	0.0244	12299.3	0.105
102	3.568	0.0436	15806.7	0.105
103	3.188	0.0405	14924.3	0.105
104	1.771	0.0273	11241.7	0.105
105	3.012	0.0399	15042.1	0.105
106	1.176	0.0212	11327.6	0.105
107	1.424	0.0285	9380.9	0.105
108	1.629	0.0372	8974.6	0.105
109	2.563	0.0472	11029.8	0.105
110	3.492	0.0526	13933.8	0.105
111	5.005	0.1222	12014.1	0.105
112	1.734	0.0295	11332.5	0.105
113	0.264	0.0081	6129.3	0.105
114	1.663	0.0435	11179.4	0.105
115	3.408	0.044	16069.1	0.105
116	3.655	0.044	17232.7	0.105
117	3.776	0.044	17803.8	0.105
118	2.296	0.0282	17105.1	0.105
119	2.707	0.0346	15230.9	0.105
120	3.2	0.0401	16603.1	0.105
121	1.726	0.0308	11524.6	0.105
122	2.229	0.0336	13693	0.105
123	3.585	0.0437	17048.1	0.105
124	2.054	0.03	13026	0.105
125	1.752	0.0247	13936.7	0.105
126	0.973	0.017	11264.5	0.105
127	1.017	0.017	11298.6	0.105
128	1.172	0.0195	11390.9	0.105
129	3.28	0.0436	14967.9	0.105

	K	L	M	N
130	3.402	0.0428	16599.8	0.105
131	3.836	0.0466	17275.3	0.105
132	3.55	0.0428	17391.7	0.105
133	3.299	0.0403	17130.9	0.105
134	3.013	0.036	17532.7	0.105
135	2.5	0.0318	15380.15	0.105
136				
137				
138				
139				
140				
141				
142				
143	4.018	0.4189	2817.105	0.105
144	0.535	0.0198	10259.6	0.105
145	0.78	0.0103	14047.8	0.105
146	1.262	0.0152	17448.8	0.105
147	0.805	0.0108	14155.3	0.105
148	0.639	0.009	12347	0.105
149	1.44	0.019	14901.1	0.105
150	1.281	0.018	14265.6	0.105
151	5.448	0.1867	13819.014	0.105
152	1.35	0.0164	17069.6	0.105
153	1.225	0.0146	17740	0.105
154	1.57	0.0186	17610	0.105
155	1.04	0.0134	15829.4	0.105
156	0.422	0.007	10926.9	0.105
157	1.116	0.0152	15025.5	0.105
158	1.562	0.0189	17415.7	0.105
159	1.485	0.0178	17469.9	0.105
160	1.287	0.0155	17500.2	0.105
161	0.996	0.0119	17548.8	0.105
162	1.053	0.0126	17576.2	0.105
163	1.034	0.0125	17342.7	0.105
164	1.394	0.0168	17275.5	0.105
165	1.5	0.0183	16882.6	0.105
166	1.692	0.0209	16997.3	0.105
167	1.608	0.0205	16491.1	0.105
168	1.527	0.0201	15807.1	0.105
169	1.405	0.0185	15640.2	0.105
170	0.362	0.006	10314.3	0.105
171	0.54	0.0083	10788.9	0.105
172	1.555	0.0213	14982.7	0.105

	K	L	M	N
173	1.815	0.0244	15225.1	0.105
174	1.232	0.0175	14118.7	0.105
175	1.388	0.0193	14589.2	0.105
176	0.863	0.0128	11963.6	0.105
177	0.328	0.0063	10195	0.105
178	0.915	0.0142	12488.5	0.105
179	1.751	0.0232	15327.8	0.105
180	1.917	0.0245	16411.2	0.105
181	1.535	0.0196	16405	0.105
182	1.133	0.0146	16130.6	0.105
183	0.959	0.0128	15047.6	0.105
184	0	0	239.532	0.105
185				
186				
187				
188				
189				
190				
191				
192				
193				
194				
195				
196				
197				
198				
199				
200				
201				
202				
203				
204				
205				
206				
207				
208				
209				
210				
211				
212				
213				
214				
215				

	K	L	M	N
216				
217				
218				
219				
220				
221				
222				
223				
224				
225				
226				
227				
228				
229				
230				
231				
232				
233				
234				
235				
236				
237				
238				
239				
240				
241				
242				
243				
244				
245				
246				
247				
248				
249				
250				
251				
252				
253				
254	3.474	0.7338	1351.847	0.105
255	0.247	0.011	4547.907	0.105
256				
257	0.872	0.0179	9917.95	0.105
258	1.91	0.0375	10874.85	0.105

	K	L	M	N
259				
260				
261				
262				
263				
264				
265				
266				
267				
268	2.201	0.1725	4989.635	0.105
269	3.297	0.0448	15107.3	0.105
270	4.605	0.0533	17049.8	0.105
271	5.657	0.063	18751.8	0.105
272	4.461	0.0565	15812	0.105
273	4.134	0.055	13803.9	0.105
274	3.997	0.0535	13416.4	0.105
275	4.891	0.0601	15094.3	0.105
276	3.847	0.0533	14169.9	0.105
277	5.162	0.0631	16237.6	0.105
278	8.35	0.0938	18640.2	0.105
279	8.089	0.0918	18474.2	0.105
280	7.434	0.082	18939.9	0.105
281	7.456	0.082	18994.4	0.105
282	6.5	0.082	16559.7	0.105
283	6.059	0.082	15437.4	0.105
284	5.925	0.082	15095.9	0.105
285	5.747	0.082	14641.9	0.105
286	6.499	0.0811	16775.8	0.105
287	7.245	0.081	18723.6	0.105
288	6.808	0.081	17594.8	0.105
289	7.146	0.081	18469.7	0.105
290	7.398	0.081	19120.8	0.105
291	7.382	0.0851	18238.5	0.105
292	7.32	0.09	17124.2	0.105
293	7.923	0.09	18534.5	0.105
294	8.214	0.09	19214.4	0.105
295	8.148	0.09	19060.2	0.105
296	8.172	0.09	19116	0.105
297	8.14	0.09	19041.9	0.105
298	8.136	0.09	19032	0.105
299	8.071	0.09	18880.9	0.105
300	8.074	0.09	18888	0.105
301	8.09	0.09	18925.6	0.105

	K	L	M	N
302	8.078	0.09	18896.8	0.105
303	7.443	0.09	17410.7	0.105
304	7.496	0.088	17947.8	0.105
305	8.238	0.086	20097.5	0.105
306	8.228	0.086	20071.6	0.105
307	8.154	0.086	19892.8	0.105
308	8.099	0.086	19758.4	0.105
309	8.164	0.0872	19638.1	0.105
310	9.278	0.1	19380.1	0.105
311	8.907	0.1	18606.6	0.105
312	9.606	0.1	20064.6	0.105
313	9.602	0.1	20058	0.105
314	9.469	0.1	19780.3	0.105
315	9.35	0.1	19531.4	0.105
316	9.45	0.1	19738.9	0.105
317	9.5	0.1	19844.3	0.105
318	9.438	0.1	19714.4	0.105
319	5.892	0.0633	19103.2	0.105
320	3.143	0.0359	18330.1	0.105
321	2.931	0.0326	18844	0.105
322	3.162	0.0353	18782.7	0.105
323	3.089	0.035	18504.7	0.105
324	3.195	0.0376	17687.1	0.105
325	1.685	0.0239	13583.3	0.105
326	3.531	0.0401	18412.1	0.105
327	3.235	0.0362	18796.1	0.105
328	1.557	0.0319	8968.577	0.105
329				
330				
331	3.635	0.1052	8417.782	0.105
332	3.969	0.0443	18784	0.105
333	3.773	0.0432	18244.4	0.105
334	2.831	0.033	17782.6	0.105
335	2.382	0.0272	18386.2	0.105
336	2.699	0.0306	18524.3	0.105
337	2.537	0.0288	18489.6	0.105
338	2.937	0.033	18612.7	0.105
339	2.988	0.0336	18637.8	0.105
340	2.852	0.033	18090.6	0.105
341	3.327	0.0374	18633.7	0.105
342	3.258	0.037	18473.7	0.105
343	3.405	0.038	18826.4	0.105
344	2.888	0.0329	18357.8	0.105

	K	L	M	N
345	2.848	0.0327	18192.9	0.105
346	2.441	0.0288	17668.9	0.105
347	2.898	0.033	18324.1	0.105
348	2.871	0.0328	18172.7	0.105
349	2.417	0.029	16409.3	0.105
350	0	0	1.26	0.106
351				
352	2.025	0.1585	3606.444	0.105
353				
354				
355				
356	1.207	0.0244	9749.02	0.105
357	3.03	0.034	18723.9	0.105
358	2.805	0.0315	18673.1	0.105
359	2.896	0.0326	18604.5	0.105
360	3.221	0.0366	18417.3	0.105
361	3.123	0.0359	18176.4	0.105
362	3.207	0.0366	18376.1	0.105
363	3.312	0.038	18351.9	0.105
364	3.618	0.0415	18276.7	0.105
365	3.449	0.039	18555.7	0.105
366	3.614	0.041	18514.2	0.105
367	3.235	0.0367	18474.5	0.105
368	3.879	0.044	18495.6	0.105
369	3.813	0.0431	18508	0.105
370	3.183	0.0365	18292.7	0.105
371	2.531	0.0352	14718.08	0.105
372				
373	2.922	0.0876	10603.487	0.105
374	1.756	0.0235	14550.2	0.105
375	3.113	0.0355	18420.6	0.105
376	3.161	0.0359	18453.7	0.105
377	3.135	0.0358	18360.7	0.105
378	3.422	0.0391	18346.1	0.105
379	3.015	0.0343	18430.5	0.105
380	2.841	0.0349	17071.2	0.105
381	2.918	0.0373	16366.9	0.105
382	3.57	0.0406	18383.3	0.105
383	3.281	0.0371	18509.6	0.105
384	3.043	0.0348	18374.2	0.105
385	2.323	0.0267	18150	0.105
386	2.354	0.0269	18306.9	0.105
387	2.702	0.0308	18338.1	0.105

	K	L	M	N
388	2.436	0.0278	18393.8	0.105
389	2.522	0.0288	18390.4	0.105
390	2.202	0.0261	17646.2	0.105
391	2.616	0.0305	17929.7	0.105
392	3.26	0.0375	18283.8	0.105
393	2.464	0.0286	18014.7	0.105
394	2.094	0.0236	18549.5	0.105
395	1.657	0.0188	18440.1	0.105
396	1.167	0.0133	18344.2	0.105
397	1.572	0.0177	18524.7	0.105
398	2.155	0.0243	18619.8	0.105
399	1.242	0.0142	18324	0.105
400	1.417	0.0159	18550.1	0.105
401	1.346	0.0151	18518.7	0.105
402	1.426	0.0163	18353.2	0.105
403	1.338	0.0151	18483.2	0.105
404	1.384	0.0164	17468.7	0.105
405	1.251	0.0163	14614.8	0.105
406	1.533	0.0185	16218	0.105
407	1.701	0.0198	17967.5	0.105
408	1.965	0.0226	18240.1	0.105
409	1.295	0.0177	14036.7	0.105
410	2.704	0.0317	17826.2	0.105
411	2.747	0.032	17931.8	0.105
412	2.731	0.0312	18362.2	0.105
413	2.405	0.0284	17029.4	0.105
414	0.003	0.0205	124.71	0.105
415				
416				
417				
418	3.282	0.315	3484.62	0.105
419	1.311	0.0525	5127.984	0.105
420				
421				
422				
423				
424				
425				
426				
427				
428				
429				
430				

	K	L	M	N
431				
432				
433				
434				
435				
436				
437				
438				
439				
440				
441				
442				
443				
444				
445				
446				
447	0.205	0.0217	2245.644	0.105
448	1.749	0.0329	11424.7	0.105
449	0.58	0.0115	10274.2	0.105
450	1.38	0.0193	12899.4	0.105
451	1.311	0.0206	11926.5	0.105
452	4.206	0.0487	18105.3	0.105
453	3.654	0.0418	18380.9	0.105
454	4.135	0.0495	17618.5	0.105
455	2.753	0.0316	18301.8	0.105
456	3.276	0.0381	17990.2	0.105
457	3.523	0.0541	13588.012	0.1058
458				
459				
460				
461				
462	4.142	0.2339	5136.418	0.105
463				
464	0.005	0.003	393.238	0.105
465	1.028	0.0198	10532.2	0.105
466	2.395	0.029	17010.4	0.105
467	3.558	0.0416	17805.9	0.105
468	2.152	0.0291	14639.9	0.105
469	3.39	0.039	18236.4	0.105
470	3.699	0.0436	17663.6	0.105
471	4.767	0.055	18209.9	0.105
472	4.709	0.0539	18317.4	0.105
473	4.702	0.0551	17174.4	0.105

	K	L	M	N
474	2.202	0.0318	11932.9	0.105
475	6.224	0.0712	18334.3	0.105
476	3.864	0.0502	14652.7	0.105
477	4.282	0.056	14246	0.105
478	0.01	0.089	23.832	0.105
479	1.577	0.691	652.066	0.105
480	2.919	0.0433	14502.2	0.105
481	2.521	0.0306	17295.3	0.105
482	3.871	0.045	18040.7	0.105
483	7.124	0.0824	18149.7	0.105
484	4.851	0.0573	17757.7	0.105
485	4.599	0.0534	18028.5	0.105
486	2.627	0.032	16771.9	0.105
487	2.12	0.0272	14977.3	0.105
488	2.092	0.0255	16940.1	0.105
489	2.69	0.0308	18339.2	0.105
490	4.158	0.0465	18715.9	0.105
491	5.321	0.0594	18779.9	0.105
492	4.669	0.0583	16400.9	0.105
493	5.175	0.062	16676.3	0.105
494	4.666	0.0568	16088.8	0.105
495	5.337	0.0621	17994.5	0.105
496	4.264	0.0524	16943	0.105
497	3.885	0.05	15479.8	0.105
498	6.843	0.0776	18468.4	0.105
499	7.248	0.0839	18035.4	0.105
500	5.33	0.0666	15183.8	0.105
501	3.795	0.0511	14500.8	0.105
502	2.308	0.037	11924.5	0.105
503	4.34	0.066	13594.4	0.105
504	2.246	0.035	12217.9	0.105
505	3.066	0.0389	15610.6	0.105
506	1.806	0.0294	11734.1	0.105
507	2.467	0.0393	11469.2	0.105
508	4.347	0.0522	17351.9	0.105
509	3.726	0.0513	14816.24	0.105
510				
511	4.343	0.1634	8322.818	0.1054
512	2.311	0.0287	16935.8	0.105
513	2.208	0.0259	17775.9	0.105
514	6.283	0.1524	15953.658	0.1053
515	9.602	0.1954	12557.6	0.105
516	2.414	0.0311	16385.3	0.105

	K	L	M	N
517	1.937	0.022	18467.3	0.105
518	1.688	0.0218	16262.7	0.105
519	3.758	0.043	18306.5	0.105
520	5.559	0.0633	18320.4	0.105
521	3.417	0.0412	17024.4	0.105
522	4.15	0.0517	16327.4	0.105
523	3.308	0.0436	14393.9	0.105
524	3.778	0.0463	15917.1	0.105
525	4.112	0.0494	16650.1	0.105
526	3.131	0.0385	15585.2	0.105
527	1.72	0.0255	12972.7	0.105
528	1.595	0.0227	13323	0.105
529	2.755	0.0324	17281.4	0.105
530	1.851	0.0234	15141.5	0.105
531	1.83	0.0239	14489.8	0.105
532	3.146	0.0371	17780.7	0.105
533	4.197	0.0476	18496.2	0.105
534	3.53	0.0443	15818.2	0.105
535	2.341	0.0347	12851.3	0.105
536	4.564	0.0512	18700.7	0.105
537	5.115	0.0584	18364.6	0.105
538	3.394	0.0439	15872.5	0.105
539	3.767	0.0456	17151.2	0.105
540	3.252	0.0381	16077.327	0.105
541				
542	1.151	0.0236	9736.23	0.105
543	2.401	0.0284	17308.7	0.105
544	3.807	0.0448	17877.7	0.105
545	3.368	0.044	15692.2	0.105
546	3.199	0.0385	17247.8	0.105
547	1.996	0.0248	16890.8	0.105
548	1.243	0.0177	13646.3	0.105
549	6.225	0.225	10178.606	0.105
550	0.841	0.014	12198.8	0.105
551	2.017	0.0268	15768.4	0.105
552	1.726	0.0238	15056.5	0.105
553	1.098	0.0176	12982.9	0.105
554	0.887	0.0151	11936.6	0.105
555	0.905	0.0157	11869.3	0.105
556	1.054	0.0179	12301.8	0.105
557	1.319	0.0203	13529.9	0.105
558	2.649	0.033	16736.5	0.105
559	2.775	0.0317	18328	0.105

	K	L	M	N
560	2.416	0.0288	17587	0.105
561	1.918	0.0223	17994	0.105
562	1.634	0.0209	16455.3	0.105
563	1.155	0.0154	15520.2	0.105
564	1.542	0.0182	17612.5	0.105
565	2.161	0.0256	17632.2	0.105
566	2.153	0.0251	17975.8	0.105
567	1.815	0.0212	17959.9	0.105
568	1.972	0.0226	18306.1	0.105
569	1.878	0.0221	17702.2	0.105
570	0.027	0.0797	641	0.105
571				
572				
573				
574				
575				
576				
577				
578				
579				
580				
581				
582				
583				
584				
585				
586				
587				
588				
589				
590				
591				
592				
593				
594				
595				
596				
597				
598				
599				
600				
601				
602				

	K	L	M	N
603				
604				
605				
606				
607				
608				
609				
610				
611				
612				
613				
614				
615				
616				
617				
618				
619				
620				
621				
622				
623				
624				
625				
626				
627				
628				
629				
630				
631				
632				
633				
634				
635				
636				
637				
638				
639				
640				
641				
642				
643				
644				
645				

	K	L	M	N
646	2.009	0.2272	2508	0.105
647	5.947	0.1183	10336.1	0.105
648	0.969	0.0154	11849.4	0.105
649	1.213	0.0163	14666.4	0.105
650	1.11	0.0149	13155.9	0.105
651	1.457	0.0178	14331.2	0.105
652	1.229	0.0165	12515.4	0.105
653	0.851	0.0125	11828.7	0.105
654	0.603	0.0108	9936.1	0.105
655	3.824	0.0451	15338.6	0.105
656	5.629	0.0633	18614	0.105
657	5.626	0.0643	18213.6	0.105
658	5.099	0.0591	17981.9	0.105
659	3.893	0.0474	16360.6	0.105
660	4.395	0.0509	18008.3	0.105
661	6.098	0.0675	18868.2	0.105
662	6.568	0.0715	19252.8	0.105
663	6.142	0.0674	19127.1	0.105
664	6.738	0.0745	18962	0.105
665	5.829	0.0645	18908.9	0.105
666	6.572	0.0742	18599.7	0.105
667	6.598	0.0761	18000.7	0.105
668	6.12	0.07	18299.6	0.105
669	4.874	0.0555	18392.7	0.105
670	5.12	0.0595	17957.4	0.105
671	5.629	0.0644	18266.7	0.105
672	5.307	0.0607	18394.8	0.105
673	7.044	0.0783	18828.7	0.105
674	6.148	0.068	18947.6	0.105
675	5.112	0.0572	18720.8	0.105
676	4.606	0.0554	17408	0.105
677	6.364	0.0712	18684.9	0.105
678	5.359	0.0601	18690.9	0.105
679	4.894	0.056	18298.2	0.105
680	4.922	0.0573	17930.1	0.105
681	4.893	0.0575	17784.7	0.105
682	6.237	0.0715	18206.4	0.105
683	7.801	0.0876	18647.1	0.105
684	7.216	0.0815	18539.1	0.105
685	5.948	0.0751	16503.4	0.105
686	2.985	0.0485	12023.9	0.105
687				
688	10.777	1.344	1682.725	0.105

	K	L	M	N
689	74.956	0.9133	17583.4	0.105
690	35.292	0.3804	18058.1	0.105
691	4.835	0.0542	18689.2	0.105
692	6.841	0.0765	18762.6	0.105
693	6.835	0.0767	18690.2	0.105
694	9.525	0.1802	15372.658	0.105
695	2.393	0.3295	3025.33	0.105
696	5.436	0.1555	9622.97	0.105
697	6.494	0.0793	16828.4	0.105
698	9.329	0.1052	18619.7	0.105
699	9.237	0.1038	18686.4	0.105
700	7.351	0.0828	18638.4	0.105
701	6.525	0.0732	18729.1	0.105
702	7.357	0.0827	18656.5	0.105
703	6.654	0.0749	18635.1	0.105
704	8.121	0.0919	18542.5	0.105
705	5.816	0.0661	18431.9	0.105
706	6.011	0.0701	17722.5	0.105
707	6.17	0.0698	18570.3	0.105
708	4.232	0.0476	18623	0.105
709	5.805	0.065	18711.2	0.105
710	7.102	0.0792	18843.6	0.105
711	8.434	0.0946	18673.7	0.105
712	8.491	0.0965	18391.1	0.105
713	6.846	0.0785	18057.7	0.105
714	6.3	0.0738	17709.5	0.105
715	5.887	0.0676	18243.8	0.105
716	7.001	0.0784	18701.6	0.105
717	7.333	0.0813	18947.3	0.105
718	6.431	0.0716	18838.2	0.105
719	6.018	0.0668	18871.7	0.105
720	5.814	0.064	19058.2	0.105
721	5.729	0.0655	18302.2	0.105
722	6.927	0.0755	19233.1	0.105
723	7.424	0.0804	19388.2	0.105
724	7.081	0.0761	19524.6	0.105
725	6.476	0.0695	19578.1	0.105
726	6.434	0.0689	19589.3	0.105
727	5.653	0.061	19389.5	0.105
728	3.817	0.0443	17973.2	0.105
729	4.087	0.0448	19095	0.105
730	7.075	0.0792	18761.8	0.105
731	8.276	0.0925	18754.1	0.105

	K	L	M	N
732	8.516	0.094	19003.5	0.105
733	6.039	0.0664	19050	0.105
734	6.864	0.0756	19030.7	0.105
735	5.344	0.0583	19192.7	0.105
736	4.86	0.0535	19003.4	0.105
737	5.575	0.0615	19045.5	0.105
738	5.696	0.0628	19075.2	0.105
739	5.142	0.0575	18729.7	0.105
740	4.87	0.0552	18510.6	0.105
741	5.124	0.0569	18884	0.105
742	5.705	0.0636	18838.6	0.105
743	5.776	0.0643	18855.5	0.105
744	6.608	0.0735	18858.1	0.105
745	6.089	0.0678	18824.5	0.105
746	5.664	0.0632	18845.5	0.105
747	4.951	0.055	18848.3	0.105
748	4.839	0.0537	18919.3	0.105
749	5	0.0566	18518.1	0.105
750	4.852	0.0554	18291.9	0.105
751	4.871	0.0544	18764.7	0.105
752	4.333	0.0485	18728.5	0.105
753	5.217	0.0594	18448.7	0.105
754	5.85	0.067	18253	0.105
755	5.424	0.0627	18101.6	0.105
756	5.681	0.0637	18690.6	0.105
757	6.576	0.0731	18863.7	0.105
758	6.225	0.0687	19033.6	0.105
759	5.369	0.0657	16902.6	0.105
760	5.249	0.0594	18461.5	0.105
761	4.924	0.0544	18945.9	0.105
762	4.931	0.0552	18762.3	0.105
763	4.845	0.0536	18946.3	0.105
764	4.825	0.0562	17931.3	0.105
765	4.202	0.0503	17453.2	0.105
766	4.66	0.0538	18169.1	0.105
767	4.811	0.0553	18202.1	0.105
768	5.419	0.0608	18697.6	0.105
769	5.109	0.0581	18378.3	0.105
770	5.688	0.0633	18840.9	0.105
771	5.196	0.123	14064.735	0.105
772				
773				
774				

	K	L	M	N
775				
776				
777				
778				
779	4.264	0.392	2792.4	0.105
780	1.691	0.0326	11874.6	0.105
781	0.99	0.0112	18637.5	0.105
782	1.741	0.02	18301.2	0.105
783	2.69	0.0306	18413	0.105
784	2.511	0.0281	18730.7	0.105
785	2.261	0.026	16574.44	0.105
786				
787				
788				
789				
790				
791				
792	0.972	0.0252	8138.315	0.105
793	2.241	0.0273	17237.8	0.105
794	3.351	0.0381	18315.4	0.105
795	3.781	0.0418	18927.6	0.105
796	4.301	0.0475	18976.3	0.105
797	2.872	0.0538	11140.608	0.105
798				
799				
800				
801	36.606	1.1692	6628.4	0.105
802	2.72	0.0321	17447.4	0.105
803	3.436	0.0381	18938.4	0.105
804	3.113	0.0346	18949.8	0.105
805	3.311	0.0367	18918.7	0.105
806	2.82	0.0313	18863.8	0.105
807	2.524	0.0284	18742.4	0.105
808	1.813	0.0208	18182.5	0.105
809	2.328	0.0295	16926.2	0.105
810	2.722	0.0341	17762.5	0.105
811	2.899	0.0332	18309.9	0.105
812	3.041	0.0343	18668.5	0.105
813	4.085	0.046	18609.1	0.105
814	3.89	0.0446	18267.4	0.105
815	3.602	0.0423	17867.6	0.105
816	2.589	0.0308	17622.2	0.105
817	1.797	0.022	17011.4	0.105

	K	L	M	N
818	0.009	0.003	390.43	0.105
819				
820				
821	3.276	0.2693	5927.64	0.105
822	2.27	0.0268	17725.6	0.105
823	3.565	0.0423	17694.4	0.105
824	3.396	0.0402	17757.1	0.105
825	2.938	0.0346	17795.3	0.105
826	2.553	0.03	17829.7	0.105
827	3.104	0.0364	17829	0.105
828	2.238	0.0281	15606.976	0.105
829				
830	1.673	0.2736	1883.021	0.105
831	5.821	0.0896	16045.5	0.105
832	3.35	0.0398	17720.4	0.105
833	3.65	0.0431	17722.3	0.105
834	3.253	0.0383	17797.4	0.105
835	3.056	0.037	17361.7	0.105
836	2.858	0.0342	17514.9	0.105
837	2.681	0.0319	17627.5	0.105
838	3.851	0.0456	17729.4	0.105
839	3.607	0.0435	17393.7	0.105
840	3.329	0.0404	17321.9	0.105
841	3.676	0.0435	17765.2	0.105
842	3.517	0.0415	17750.1	0.105
843	3.19	0.038	17609.2	0.105
844	3.298	0.0394	17523.9	0.105
845	2.878	0.0341	17696	0.105
846	2.534	0.0298	17820.7	0.105
847	2.35	0.0277	17848.4	0.105
848	2.459	0.0289	17926	0.105
849	2.44	0.0286	17907.7	0.105
850	2.248	0.0266	17771.7	0.105
851	2.215	0.0264	17640.6	0.105
852	2.133	0.0253	17714	0.105
853	2.221	0.026	17913.2	0.105
854	2.249	0.0262	18024.9	0.105
855	2.238	0.0263	17865	0.105
856	2.374	0.0279	17816.4	0.105
857	2.184	0.0262	17474.1	0.105
858	1.922	0.0232	17140.7	0.105
859	2.298	0.0274	17616.8	0.105
860	3.903	0.0469	17418.6	0.105

	K	L	M	N
861	4.093	0.0483	17823.2	0.105
862	4.383	0.0515	17893.7	0.105
863	4.726	0.0556	17815.7	0.105
864	4.536	0.0531	17926.7	0.105
865	4.611	0.0535	18064.4	0.105
866	4.555	0.053	18019.5	0.105
867	4.62	0.0542	17873.7	0.105
868	4.344	0.051	17895	0.105
869	4.27	0.0506	17704.7	0.105
870	4.072	0.0484	17605.8	0.105
871	3.1	0.0386	16029.3	0.105
872	3.613	0.0428	17704.9	0.105
873	3.554	0.0415	17949.1	0.105
874	3.461	0.0402	18055	0.105
875	4.198	0.0495	17782.1	0.105
876	5.541	0.0643	18079.7	0.105
877	4.843	0.0561	18100.2	0.105
878	5.966	0.0693	18050.1	0.105
879	5.038	0.0588	17993.9	0.105
880	3.543	0.0418	17878.5	0.105
881	3.864	0.0446	18196.2	0.105
882	4.429	0.051	18200.4	0.105
883	4.523	0.0519	18256.5	0.105
884	6.177	0.0712	18210.3	0.105
885	6.149	0.071	18181.7	0.105
886	4.73	0.0549	18097.6	0.105
887	4.603	0.053	18222.4	0.105
888	3.524	0.0405	18249.2	0.105
889	3.254	0.0374	18271.9	0.105
890	3.596	0.0411	18384.3	0.105
891	3.844	0.0438	18353.4	0.105
892	4.107	0.0471	18304	0.105
893	5.135	0.0597	18061.5	0.105
894	5.28	0.0607	18239.8	0.105
895	6.352	0.0728	18310	0.105
896	5.79	0.0677	17923.4	0.105
897	4.552	0.0533	17871.4	0.105
898	4.307	0.0498	18089.8	0.105
899	4.235	0.0487	18278.8	0.105
900	4.125	0.0476	18159.5	0.105
901	4.373	0.0503	18265.5	0.105
902	5.127	0.0598	17947.6	0.105
903	4.269	0.0787	15137.14	0.105

	K	L	M	N
904				
905	2.476	0.4008	2886.44	0.105
906	0.074	0.0285	1871.102	0.105
907	1.531	0.1731	11761.1	0.105
908	3.677	0.0418	18509.3	0.105
909	3.557	0.0405	18390.7	0.105
910	4.497	0.0515	18322.1	0.105
911	4.014	0.0458	18406.9	0.105
912	3.353	0.0393	17744.3	0.105
913	3.44	0.0398	18079.7	0.105
914	3.933	0.0448	18432	0.105
915	3.493	0.0397	18468.6	0.105
916	3.503	0.04	18372.6	0.105
917	4.402	0.0492	18741.3	0.105
918	3.935	0.0444	18548.2	0.105
919	3.589	0.0411	18239.4	0.105
920	3.565	0.041	18258.9	0.105
921	8.911	0.1013	18397.3	0.105
922	5.088	0.0583	18287.7	0.105
923	5.965	0.0678	18429.6	0.105
924	4.311	0.0503	17975.1	0.105
925	3.49	0.041	17846.5	0.105
926	3.497	0.0408	17929.3	0.105
927	3.828	0.046	17280.4	0.105
928	4.848	0.0569	17881.8	0.105
929	4.414	0.0515	17931.9	0.105
930	4.736	0.0553	18003.8	0.105
931	4.904	0.0569	18055.6	0.105
932	5.447	0.0642	17667	0.105
933	4.93	0.0582	17690	0.105
934	4.911	0.0583	17686.7	0.105
935	4.84	0.0584	17292.5	0.105
936	3.388	0.0405	17595.2	0.105
937	2.989	0.035	17868.9	0.105
938	2.686	0.0318	17751.2	0.105
939	2.45	0.0294	17485	0.105
940	5.532	0.0853	14550.2	0.105
941	0.203	0.0051	8137.4	0.105
942	0.37	0.0083	9019.1	0.105
943	0.286	0.007	8359	0.105
944	0.742	0.0149	8580.034	0.105
945				
946				

	K	L	M	N
947				
948				
949				
950				
951				
952				
953				
954				
955				
956				
957				
958				
959				
960				
961				
962				
963				
964				
965				
966				
967				
968				
969				
970				
971				
972				
973				
974				
975				
976				
977				
978				
979				
980				
981				
982	3.902	0.3878	3049.63	0.105
983	0.065	0.0015	8739.6	0.105
984	0.143	0.0029	9793	0.105
985	0.259	0.006	9003.5	0.105
986	0.332	0.0078	8806.6	0.105
987	0.561	0.0112	10436.8	0.105
988	0.532	0.0104	10536.1	0.105
989	0.392	0.0088	9259.2	0.105

	K	L	M	N
990	0.605	0.0142	8915.6	0.105
991	0.731	0.0175	8762.1	0.105
992	0.778	0.0173	9402.3	0.105
993	0.904	0.0178	10569.3	0.105
994	0.844	0.0171	10338.4	0.105
995	0.804	0.0162	10360.8	0.105
996	0.918	0.0194	9815.5	0.105
997	0.708	0.0152	9621.4	0.105
998	0.647	0.014	9647.6	0.105
999	0.693	0.0144	10006.8	0.105
1000	0.698	0.0142	10214.5	0.105
1001	0.663	0.0137	10155.8	0.105
1002	0.859	0.1063	8670.694	0.105
1003				
1004				
1005				
1006				
1007				
1008				
1009	17.667	1.902	1948.05	0.105
1010	20.149	0.574	10755.6	0.105
1011	1.754	0.0231	13957.1	0.105
1012	1.05	0.017	12015.9	0.105
1013	2.336	0.0306	15616.9	0.105
1014	2.943	0.0351	17088.6	0.105
1015	2.136	0.0267	15640.4	0.105
1016	2.896	0.0333	18220.2	0.105
1017	3.425	0.0395	18239.1	0.105
1018	3.09	0.0355	18218.2	0.105
1019	3.124	0.0358	18314.8	0.105
1020	3.004	0.0344	18282.4	0.105
1021	2.974	0.0346	17987.4	0.105
1022	3.183	0.0365	18291.4	0.105
1023	3.559	0.0409	18237	0.105
1024	3.552	0.0414	18005.9	0.105
1025	3.731	0.0439	17816.3	0.105
1026	4.096	0.0474	18131.8	0.105
1027	3.869	0.0454	17833.9	0.105
1028	3.605	0.0437	17306.2	0.105
1029	3.59	0.0428	17548.9	0.105
1030	3.808	0.0465	16969.8	0.105
1031	3.782	0.0451	17543.4	0.105
1032	3.325	0.0401	17338.9	0.105

	K	L	M	N
1033	3.665	0.0435	17666.9	0.105
1034	4.086	0.0484	17682.1	0.105
1035	4.319	0.0515	17577.3	0.105
1036	4.529	0.0538	17652.1	0.105
1037	4.374	0.0518	17672.7	0.105
1038	3.897	0.0463	17627.4	0.105
1039	4.389	0.052	17720.7	0.105
1040	4.518	0.0534	17774.9	0.105
1041	4.146	0.0505	17050.7	0.105
1042	5.473	0.0639	17984.7	0.105
1043	5.231	0.0613	17917.4	0.105
1044	4.539	0.053	17906.8	0.105
1045	4.07	0.0474	17973.1	0.105
1046	4.002	0.047	17789.4	0.105
1047	4.16	0.0492	17757.1	0.105
1048	4.515	0.0535	17695.9	0.105
1049	4.481	0.0528	17819.3	0.105
1050	4.215	0.0496	17797	0.105
1051	2.706	0.0361	14761.3	0.105
1052	3.831	0.0476	16705.3	0.105
1053	3.992	0.0486	16971.1	0.105
1054	3.583	0.045	15960.8	0.105
1055	3.527	0.0442	15589.9	0.105
1056	4.249	0.0518	16529.8	0.105
1057	4.426	0.0521	17806.7	0.105
1058	4.382	0.052	17730.2	0.105
1059	4.469	0.0528	17753.4	0.105
1060	4.748	0.0561	17735.6	0.105
1061	6.017	0.071	17778.4	0.105
1062	5.608	0.0673	17292.4	0.105
1063	5.198	0.0668	15964.5	0.105
1064	6.075	0.0719	17701.7	0.105
1065	4.214	0.0561	15371.3	0.105
1066	2.381	0.0368	12343.6	0.105
1067	1.076	0.022	9394.8	0.105
1068	0.616	0.0154	8338.4	0.105
1069	3.252	0.0447	14900.4	0.105
1070	4.567	0.0541	17691.8	0.105
1071	3.93	0.0476	17322.7	0.105
1072	3.94	0.0467	17651.4	0.105
1073	4.114	0.05	16969	0.105
1074	4.256	0.051	17515.2	0.105
1075	3.956	0.0479	17097.8	0.105

	K	L	M	N
1076	3.633	0.0441	16974.3	0.105
1077	4.007	0.0468	17991.9	0.105
1078	3.809	0.0447	17857.9	0.105
1079	3.584	0.0421	17843.7	0.105
1080	3.592	0.042	17929	0.105
1081	6.441	0.0769	17545.7	0.105
1082	7.891	0.0936	17662.7	0.105
1083	6.925	0.0823	17650.8	0.105
1084	5.747	0.0679	17763.2	0.105
1085	1.712	0.0409	8036.49	0.105
1086				
1087				
1088	5.636	1.4335	1257.83	0.105
1089	2.233	0.0452	12223.3	0.105
1090	3.861	0.0448	18039.3	0.105
1091	4.071	0.0487	17433.4	0.105
1092	3.898	0.0481	16827.3	0.105
1093	4.075	0.05	17061.3	0.105
1094	4.47	0.0519	18062.2	0.105
1095	4.59	0.0547	17591.9	0.105
1096	4.057	0.0481	17647.3	0.105
1097	4.172	0.0487	17992.6	0.105
1098	4.588	0.0531	18114.4	0.105
1099	5.148	0.0599	18000.5	0.105
1100	5.163	0.0597	18170.7	0.105
1101	6.441	0.0743	18192.2	0.105
1102	5.796	0.0668	18201.2	0.105
1103	5.546	0.064	18130.6	0.105
1104	6.127	0.0706	18217.7	0.105
1105	5.542	0.064	18156.9	0.105
1106	4.445	0.0512	18225.7	0.105
1107	5.345	0.0617	18169.2	0.105
1108	4.374	0.0505	18148.9	0.105
1109	4.529	0.0541	17575.8	0.105
1110	4.83	0.0555	18242.9	0.105
1111	5.096	0.0585	18300.6	0.105
1112	4.957	0.057	18251.2	0.105
1113	5.136	0.0589	18313.2	0.105
1114	4.666	0.0536	18291.7	0.105
1115	4.249	0.049	18161.4	0.105
1116	3.696	0.0443	17491.5	0.105
1117	2.472	0.034	14853.3	0.105
1118	3.989	0.0474	17488.2	0.105

	K	L	M	N
1119	3.95	0.0452	18308.6	0.105
1120	4.056	0.0464	18356.5	0.105
1121	3.996	0.0458	18267.9	0.105
1122	4.301	0.0493	18297.2	0.105
1123	3.918	0.0446	18378.3	0.105
1124	3.668	0.0433	17296.7	0.105
1125	4.136	0.0472	18350.4	0.105
1126	4.835	0.0554	18294.1	0.105
1127	4.286	0.0497	18077.7	0.105
1128	4.009	0.0469	17939.9	0.105
1129	3.546	0.043	17148.9	0.105
1130	3.041	0.0381	16011.9	0.105
1131	4.111	0.0483	17657.1	0.105
1132	3.654	0.0453	16138.7	0.105
1133	4.886	0.0574	17797.1	0.105
1134	5.384	0.0614	18393.3	0.105
1135	4.173	0.0515	16663.6	0.105
1136	0.702	0.0149	8756.69	0.105
1137				
1138				
1139				
1140	4.472	0.2248	10835.541	0.105
1141	2.913	0.0335	18235.3	0.105
1142	2.601	0.0304	17932.8	0.105
1143	3.192	0.0369	18151.2	0.105
1144	3.562	0.0433	17159.8	0.105
1145	4.195	0.0482	18262	0.105
1146	3.123	0.0398	16024.2	0.105
1147	2.185	0.032	14069.5	0.105
1148	0.265	0.0211	2513.322	0.105
1149				
1150				
1151				
1152				
1153				
1154				
1155	2.681	2.596	216.568	0.105
1156	3.038	0.1019	8264.1	0.105
1157	2.541	0.0304	17533.1	0.105
1158	4.235	0.0502	17735.9	0.105
1159	4.528	0.0528	17936.5	0.105
1160	13.466	0.1608	17564.2	0.105
1161	4.713	0.0567	17458.3	0.105

	K	L	M	N
1162	3.868	0.0468	17320.6	0.105
1163	5.026	0.0599	17595.6	0.105
1164	3.091	0.0441	12526	0.105
1165	4.849	0.0596	17002.3	0.105
1166	5.188	0.0615	17690.9	0.105
1167	4.422	0.0521	17810.7	0.105
1168	3.258	0.0386	17734.7	0.105
1169	3.748	0.0442	17755.6	0.105
1170	4.919	0.0586	17637.9	0.105
1171	5.186	0.0613	17759.8	0.105
1172	4.388	0.0517	17820.1	0.105
1173	4.505	0.053	17815.3	0.105
1174	4.371	0.0522	17540.8	0.105
1175	5.133	0.0604	17832.5	0.105
1176	4.594	0.0541	17799	0.105
1177	4.649	0.0553	17494.6	0.105
1178	3.736	0.0458	16228.2	0.105
1179	5.683	0.0674	17687.9	0.105
1180	4.113	0.0521	15587.8	0.105
1181	2.793	0.0412	13736.6	0.105
1182	1.692	0.0418	7853.83	0.105
1183				
1184				
1185				
1186				
1187				
1188				
1189				
1190				
1191				
1192				
1193				
1194				
1195				
1196	2.417	2.315	219.04	0.105
1197	3.516	0.092	7306.402	0.105
1198	2.674	0.0333	16839.8	0.105
1199	2.982	0.0358	17358.9	0.105
1200	3.962	0.0457	18188.4	0.105
1201	3.642	0.0423	18065.2	0.105
1202	4.081	0.0473	18168.5	0.105
1203	3.357	0.0394	17895.8	0.105
1204	3.707	0.0434	17960.5	0.105

	K	L	M	N
1205	3.591	0.0417	18053	0.105
1206	3.451	0.0394	18329.1	0.105
1207	3.398	0.0398	17909.9	0.105
1208	3.597	0.041	18403.5	0.105
1209	3.462	0.0388	18678	0.105
1210	3.473	0.0384	19001.2	0.105
1211	3.619	0.04	18983	0.105
1212	3.597	0.0397	19027.9	0.105
1213	3.923	0.0437	18788.1	0.105
1214	2.471	0.0301	16753.3	0.105
1215	1.975	0.0254	15002.2	0.105
1216	2.511	0.0308	16301.1	0.105
1217	3.178	0.038	17481.3	0.105
1218	2.762	0.0334	16730.8	0.105
1219	2.996	0.035	17899.6	0.105
1220	1.969	0.0253	15609.7	0.105
1221	3.832	0.0447	17990.3	0.105
1222	3.596	0.0415	18091	0.105
1223	3.762	0.0435	18150.1	0.105
1224	3.936	0.0455	18114.7	0.105
1225	3.457	0.0411	17540	0.105
1226	3.933	0.0457	17984.1	0.105
1227	4	0.0462	18183.4	0.105
1228	3.836	0.0442	18225.4	0.105
1229	3.63	0.0431	17011.5	0.105
1230	4.404	0.0503	18410.8	0.105
1231	4.328	0.0498	18291.7	0.105
1232	4.503	0.0515	18319.3	0.105
1233	1.878	0.0405	9534.798	0.105
1234				
1235				
1236	36.526	1.1715	6886.013	0.105
1237	1.713	0.0197	18175.2	0.105
1238	2.752	0.0322	18008.5	0.105
1239	2.574	0.0311	17030.5	0.105
1240	3.097	0.0359	18085.9	0.105
1241	0.359	0.0083	8747.8	0.105
1242	0.404	0.0098	8610.7	0.105
1243	0.973	0.0181	10239	0.105
1244	0.563	0.022	4028.15	0.105
1245				
1246				
1247				

	K	L	M	N
1248	62.245	1.353	9650.264	0.105
1249	75.827	0.9539	16844	0.105
1250	32.98	0.3602	18710.3	0.105
1251	4.409	0.0504	18340.7	0.105
1252	3.608	0.0413	18340.3	0.105
1253	3.878	0.0443	18301.7	0.105
1254	3.931	0.0453	18237.8	0.105
1255	2.687	0.0327	16656.8	0.105
1256	1.196	0.0202	11815.7	0.105
1257	2.757	0.0352	16122.6	0.105
1258	0.755	0.0138	10422	0.105
1259	3.195	0.0404	16058.3	0.105
1260	3.631	0.0437	15963.6	0.105
1261	2.406	0.0312	14651.5	0.105
1262	1.189	0.0198	12066	0.105
1263	0.828	0.0155	11076.2	0.105
1264	1.224	0.0198	11751.5	0.105
1265	1.452	0.0563	10996.016	0.105
1266				
1267				
1268				
1269				
1270				
1271				
1272				
1273				
1274				
1275				
1276				
1277				
1278				
1279				
1280				
1281				
1282				
1283				
1284				
1285				
1286				
1287				
1288				
1289				
1290				

	K	L	M	N
1291				
1292				
1293				
1294				
1295				
1296				
1297				
1298				
1299				
1300				
1301				
1302				
1303				
1304				
1305				
1306				
1307				
1308				
1309				
1310				
1311				
1312				
1313				
1314				
1315				
1316				
1317				
1318				
1319				
1320				
1321				
1322				
1323				
1324				
1325				
1326				
1327				
1328				
1329				
1330				
1331				
1332				
1333				

	K	L	M	N
1334				
1335				
1336				
1337				
1338				
1339				
1340				
1341				
1342				
1343				
1344				
1345				
1346				
1347				
1348				
1349				
1350				
1351				
1352				
1353				
1354				
1355				
1356				
1357				
1358				
1359				
1360				
1361	3.68	0.3765	2076.764	0.105
1362	0.943	0.0511	3793.486	0.105
1363	4.138	0.0987	7934.64	0.105
1364				
1365				
1366				
1367				
1368	0.012	1.656	1.47	0.105
1369	3.185	0.1848	4305.3	0.105
1370	0.042	0.0013	5152.1	0.105
1371				
1372	0.352	0.0361	1945.665	0.105
1373	2.35	0.0708	3957.6	0.105
1374	0.021	0.0007	3376.4	0.105
1375	0.042	0.0016	3079.8	0.105
1376	0.113	0.0045	3286.9	0.105

	K	L	M	N
1377	1.791	0.0224	11379.8	0.105
1378	3.941	0.0448	18455.6	0.105
1379	4.28	0.0488	18404.4	0.105
1380	4.728	0.0539	18401.7	0.105
1381	4.214	0.0488	17900.5	0.105
1382	2.712	0.0373	13730.8	0.105
1383	2.318	0.0325	13266	0.105
1384	2.605	0.0329	14479.4	0.105
1385	5.226	0.0591	18552.7	0.105
1386	4.782	0.0544	18423.4	0.105
1387	3.832	0.0456	17422.4	0.105
1388	4.697	0.0528	18648.3	0.105
1389	4.247	0.0489	17857.7	0.105
1390	3.168	0.0385	16236.2	0.105
1391	3.923	0.0456	17796.3	0.105
1392	3.526	0.042	16709.1	0.105
1393	1.798	0.0274	12476.5	0.105
1394	3.056	0.0408	15266.2	0.105
1395	1.633	0.0266	12574.6	0.105
1396	0.73	0.0164	9446.1	0.105
1397	2.404	0.0349	13247.9	0.105
1398	2.496	0.0398	12457	0.105
1399	4.485	0.061	15131	0.105
1400	5.862	0.0758	16174.9	0.105
1401	6.146	0.0794	16090.5	0.105
1402	3.57	0.052	13116.8	0.105
1403	3.167	0.0424	14004.4	0.105
1404	4.152	0.0544	15724.4	0.105
1405	3.366	0.0475	13560.5	0.105
1406	4.921	0.0636	16134.5	0.105
1407	4.77	0.0619	15932	0.105
1408	6.08	0.0769	16558	0.105
1409	5.108	0.0674	15372.4	0.105
1410	2.62	0.0433	11015.1	0.105
1411	3.693	0.0574	12321.4	0.105
1412	1.145	0.0293	8201.9	0.105
1413	3.47	0.049	12826.4	0.105
1414	12.498	0.3052	11250.304	0.105
1415	4.788	0.0574	16128.8	0.105
1416	4.154	0.0486	17108.2	0.105
1417	1.691	0.0261	12280.4	0.105
1418	3.636	0.0436	15728.8	0.105
1419	2.968	0.041	13724.9	0.105

	K	L	M	N
1420	4.011	0.0519	14592.5	0.105
1421	3.932	0.0503	15746	0.105
1422	0.688	0.0147	9844.3	0.105
1423	0.845	0.0178	9987.7	0.105
1424	0.854	0.0173	10103.2	0.105
1425	2.963	0.0418	13531.4	0.105
1426	0.937	0.02	9872.6	0.105
1427	2.029	0.0353	11081.5	0.105
1428	4.868	0.0625	15225.1	0.105
1429	4.218	0.0541	15395.2	0.105
1430	4.243	0.0539	14539.8	0.105
1431	2.559	0.04	11800.5	0.105
1432	1.586	0.029	10912.2	0.105
1433	5.709	0.0673	16471.5	0.105
1434	5.694	0.0628	19015.4	0.105
1435	6.181	0.0669	19332.3	0.105
1436	6.577	0.0732	18807.9	0.105
1437	5.454	0.0619	18281.6	0.105
1438	5.286	0.0619	17398.3	0.105
1439	4.129	0.0508	15739.3	0.105
1440	3.037	0.0379	14981.5	0.105
1441	2.429	0.0316	13761.5	0.105
1442	0.725	0.0149	10117.5	0.105
1443	1.833	0.027	12264.2	0.105
1444	1.349	0.0217	11708	0.105
1445	0.775	0.0161	10118.7	0.105
1446	3.093	0.0388	14508.552	0.105
1447				
1448				
1449				
1450				
1451				
1452	2.772	0.5816	831.465	0.105
1453	1.516	0.1045	2812.856	0.105
1454	0.873	0.011	15820.1	0.105
1455	1.49	0.017	17491.2	0.105
1456	2.27	0.0258	16952.1	0.105
1457	2.352	0.027	17309	0.105
1458	3.107	0.034	18761.3	0.105
1459	1.111	0.0166	12114.4	0.105
1460	4.242	0.0465	19140	0.105
1461	4.006	0.0441	18455	0.105
1462	3.657	0.0413	17926.7	0.105

	K	L	M	N
1463	3.742	0.0413	18895.1	0.105
1464	3.209	0.0365	17552.4	0.105
1465	3.284	0.0364	17425.5	0.105
1466	4.157	0.0448	19422.7	0.105
1467	4.048	0.0445	19013.9	0.105
1468	3.992	0.0453	18377.8	0.105
1469	4.498	0.0499	18715.7	0.105
1470	5.209	0.0565	19245.2	0.105
1471	4.542	0.0492	19369.9	0.105
1472	4.771	0.0515	19426.8	0.105
1473	4.778	0.0531	18617.7	0.105
1474	4.876	0.054	18479.1	0.105
1475	4.532	0.0525	17510.2	0.105
1476	3.423	0.0423	16396	0.105
1477	5.651	0.0697	17017.6	0.105
1478	5.07	0.0596	16718.6	0.105
1479	1.137	0.0213	10683.9	0.105
1480	1.106	0.0199	11071.2	0.105
1481	3.413	0.0411	15922.9	0.105
1482	0.932	0.0265	5855.64	0.105
1483				
1484	4.571	1.9225	562.06	0.105
1485	2.007	0.0278	15077.9	0.105
1486	3.119	0.0373	16651.3	0.105
1487	0.849	0.0163	10566.1	0.105
1488	3.704	0.0432	16452.6	0.105
1489	3.144	0.0376	16680.2	0.105
1490	3.911	0.0436	18837.3	0.105
1491	2.413	0.0303	15452.9	0.105
1492	1.044	0.0168	11734.8	0.105
1493	0.541	0.0117	9671.7	0.105
1494	0.546	0.0119	9666.2	0.105
1495	0.627	0.0124	10332.7	0.105
1496	1.945	0.0265	13109.2	0.105
1497	4.127	0.0466	18455.5	0.105
1498	3.266	0.0371	18346.1	0.105
1499	2.238	0.0275	15578.9	0.105
1500	0.913	0.0158	11341.3	0.105
1501	0.665	0.0137	10053.5	0.105
1502	1.049	0.019	10906.6	0.105
1503	1.082	0.0207	10710.7	0.105
1504	1.099	0.0196	11194.6	0.105
1505	1.638	0.023	13146.9	0.105

	K	L	M	N
1506	2.456	0.0315	15513.9	0.105
1507	1.597	0.0257	12219.7	0.105
1508	1.021	0.0203	10458.5	0.105
1509	1.925	0.027	13239.4	0.105
1510	3.992	0.046	17788.9	0.105
1511	2.531	0.0327	15125.5	0.105
1512	3.292	0.0368	18808.3	0.105
1513	2.903	0.0319	19161	0.105
1514	2.63	0.0299	18113	0.105
1515	4.154	0.0468	18155.7	0.105
1516	4.207	0.0459	19216	0.105
1517	4.57	0.0501	19154.3	0.105
1518	4.083	0.0464	17776.5	0.105
1519	3.985	0.0448	18581.4	0.105
1520	3.62	0.0416	18185.8	0.105
1521	3.63	0.041	18553.9	0.105
1522	3.604	0.0399	18912.5	0.105
1523	3.16	0.0349	18994.9	0.105
1524	1.701	0.0218	14945.9	0.105
1525	0.012	0.0065	366.075	0.105
1526	2.089	2.745	159.624	0.105
1527				
1528				
1529	23.874	2.745	1824.591	0.105
1530	17.399	0.6864	11366.8	0.105
1531	1.085	0.0123	18197.4	0.105
1532	1.9	0.0213	18759.8	0.105
1533	2.044	0.0229	18872.6	0.105
1534	1.799	0.02	18864.1	0.105
1535	1.58	0.0179	17893.3	0.105
1536	0.89	0.0113	14613.4	0.105
1537	1.753	0.0192	19105	0.105
1538	2.308	0.0266	18145.3	0.105
1539	0.454	0.0087	10651	0.105
1540	2.346	0.0277	17470.1	0.105
1541	1.889	0.0226	17338.9	0.105
1542	2.048	0.0262	16383.6	0.105
1543	2.285	0.0273	16344.1	0.105
1544	1.87	0.0228	15399	0.105
1545	0.729	0.0133	11133.7	0.105
1546	0.623	0.0132	9938.6	0.105
1547	0.5	0.0105	10064.3	0.105
1548	0.857	0.0179	10079.4	0.105

	K	L	M	N
1549	0.584	0.0122	10012.5	0.105
1550	0.622	0.0132	9932.1	0.105
1551	0.71	0.0151	9897	0.105
1552	3.309	0.0455	14832.7	0.105
1553	1.77	0.0363	9500	0.105
1554	3.341	0.0524	13328	0.105
1555	4.249	0.0644	13822.4	0.105
1556	4.52	0.0704	13366.9	0.105
1557	2.972	0.051	11982.9	0.105
1558	3.564	0.0525	14243.5	0.105
1559	3.575	0.0525	14289.6	0.105
1560	3.07	0.0477	13410.3	0.105
1561	2.508	0.04	12896.3	0.105
1562	0.014	0.0085	284.32	0.105
1563	3.754	0.5126	3316.782	0.105
1564	2.079	0.0358	12053.3	0.105
1565	3.053	0.0454	14179.1	0.105
1566	2.813	0.0408	14507.2	0.105
1567	2.802	0.0407	14425.8	0.105
1568	3.031	0.0447	14227.7	0.105
1569	3.164	0.0461	14405.4	0.105
1570	3.55	0.0519	14406.1	0.105
1571	3.372	0.0487	14543.5	0.105
1572	3.264	0.0473	14498	0.105
1573	3.242	0.0469	14513.5	0.105
1574	2.998	0.0434	14507.5	0.105
1575	3.152	0.0465	14228	0.105
1576	3.482	0.05	14586.1	0.105
1577	3.336	0.0483	14474	0.105
1578	3.2	0.0463	14507.1	0.105
1579	3.662	0.0533	14425.4	0.105
1580	3.413	0.0496	14450.1	0.105
1581	3.273	0.0473	14547.1	0.105
1582	3.418	0.0491	14605.2	0.105
1583	3.393	0.0498	14310.2	0.105
1584	2.774	0.0426	13743.9	0.105
1585	3.091	0.0458	14152.4	0.105
1586	3.415	0.0501	14301.1	0.105
1587	3.632	0.053	14394.2	0.105
1588	3.502	0.0508	14415.8	0.105
1589	3.371	0.0489	14478.1	0.105
1590	3.343	0.0494	14188.6	0.105
1591	3.187	0.0483	13811.9	0.105

	K	L	M	N
1592	3.465	0.053	13614.6	0.105
1593	3.266	0.0493	14011.1	0.105
1594	2.919	0.0417	14730.2	0.105
1595	2.856	0.0412	14546.7	0.105
1596	2.382	0.0343	14544.2	0.105
1597	2.486	0.0361	14454.7	0.105
1598	2.282	0.0348	13710.4	0.105
1599	2.213	0.0327	14168.7	0.105
1600	2.496	0.0356	14698.1	0.105
1601	2.441	0.0342	14994.2	0.105
1602	2.534	0.036	14743	0.105
1603	2.545	0.0395	13450	0.105
1604	2.581	0.0383	14137.8	0.105
1605	1.251	0.0264	9440.3	0.105
1606	1.039	0.0223	8998.4	0.105
1607	1.74	0.0334	9702	0.105
1608	0	0	0.595	0.105
1609				
1610				
1611				
1612				
1613				
1614	22.644	4.003	1186.64	0.105
1615	18.335	1.0224	8298.7	0.105
1616	2.81	0.0405	14419.5	0.105
1617	2.993	0.0424	14760.1	0.105
1618	2.774	0.0421	13415.4	0.105
1619	2.407	0.0389	12333	0.105
1620	1.026	0.024	8625.7	0.105
1621	2.681	0.0406	13281.6	0.105
1622	3.326	0.0463	15074.7	0.105
1623	2.793	0.0392	14963.7	0.105
1624	2.083	0.0314	13424.1	0.105
1625	3.143	0.0438	15045	0.105
1626	1.604	0.0268	11111.4	0.105
1627	1.262	0.0243	9913.7	0.105
1628	2.959	0.044	14026.2	0.105
1629	5.962	0.0894	13908.6	0.105
1630	6.143	0.0871	14761.8	0.105
1631	2.302	0.0429	10645.2	0.105
1632	1.397	0.0276	9366.6	0.105
1633	0.55	0.0147	7617.9	0.105
1634	0.587	0.016	7642.9	0.105

	K	L	M	N
1635	0.952	0.025	7918.6	0.105
1636	2.821	0.049	10541.5	0.105
1637	0.659	0.0209	6154.598	0.105
1638				
1639				
1640				
1641				
1642				
1643				
1644				
1645				
1646				
1647				
1648				
1649				
1650				
1651				
1652				
1653				
1654				
1655				
1656				
1657				
1658				
1659				
1660				
1661				
1662				
1663				
1664				
1665				
1666				
1667				
1668				
1669				
1670				
1671				
1672				
1673				
1674				
1675				
1676				
1677				

	K	L	M	N
1678				
1679				
1680				
1681				
1682				
1683				
1684				
1685				
1686				
1687				
1688				
1689				
1690				
1691				
1692				
1693				
1694				
1695				
1696				
1697				
1698				
1699				
1700				
1701				
1702				
1703				
1704				
1705				
1706				
1707				
1708	2.847	0.5067	2140.005	0.105
1709	2.439	0.0679	8521.3	0.105
1710	2.445	0.0507	9160.5	0.105
1711	2.887	0.0706	8592.928	0.105
1712				
1713				
1714	3.143	0.2347	4247.425	0.105
1715	0.743	0.0212	7208.1	0.105
1716	0.736	0.0209	7143.9	0.105
1717	0.55	0.0162	7056.2	0.105
1718	1.84	0.0363	9109	0.105
1719	2.967	0.0539	10728.4	0.105
1720	2.958	0.0562	9794.5	0.105

	K	L	M	N
1721	4.007	0.0657	11779.7	0.105
1722	6.187	0.0953	13373.9	0.105
1723	1.187	0.0361	6872	0.105
1724	1.436	0.0441	6818.9	0.105
1725	1.677	0.0482	7162	0.105
1726	6.012	0.0965	13025.1	0.105
1727	8.475	0.1256	14141	0.105
1728	5.304	0.1012	10757.9	0.105
1729	6.685	0.1149	12044.1	0.105
1730	4.676	0.0839	11399.1	0.105
1731	4.46	0.08	10981.8	0.105
1732	5.131	0.0833	12579.1	0.105
1733	5.805	0.0877	13886.1	0.105
1734	5.392	0.0853	13120.4	0.105
1735	1.684	0.0478	7257.7	0.105
1736	4.018	0.0733	11007.5	0.105
1737	3.346	0.0671	9799.1	0.105
1738	3.691	0.066	11064.1	0.105
1739	4.261	0.0712	12249.3	0.105
1740	5.195	0.0779	13960.8	0.105
1741	6.682	0.1	14000.4	0.105
1742	5.83	0.0887	13718.8	0.105
1743	4.505	0.0703	13433.5	0.105
1744	4.739	0.0738	13445.5	0.105
1745	4.293	0.0672	13356	0.105
1746	3.7	0.0571	13578.1	0.105
1747	2.978	0.0509	12138.8	0.105
1748	3.861	0.0592	13717.4	0.105
1749	3.275	0.0503	13673.1	0.105
1750	2.269	0.0351	13560	0.105
1751	2.072	0.0328	12908	0.105
1752	1.343	0.0275	9611.5	0.105
1753	1.71	0.0302	11356.4	0.105
1754	2.884	0.0445	13504.2	0.105
1755	3.084	0.0472	13719.6	0.105
1756	3.12	0.0478	13676.9	0.105
1757	2.641	0.0452	11821.435	0.105
1758				
1759				
1760				
1761	1.74	3.921	93.08	0.105
1762	4.49	0.243	6144.4	0.105
1763	2.41	0.037	13711.6	0.105

	K	L	M	N
1764	2.74	0.0398	14479.1	0.105
1765	2.339	0.0376	12867.5	0.105
1766	2	0.039	10467.7	0.105
1767	0.976	0.0255	7706.1	0.105
1768	1.741	0.0321	10598.6	0.105
1769	2.799	0.0453	12520.9	0.105
1770	2.219	0.0386	11459.5	0.105
1771	1.531	0.0307	10044.1	0.105
1772	2.894	0.0455	12768.9	0.105
1773	3.028	0.0475	13153	0.105
1774	1.352	0.4571	6570.468	0.105
1775				
1776	15.725	10.3768	1762.264	0.0963
1777				
1778				
1779				
1780	2.509	2.4773	269.115	0.105
1781	0.073	0.0333	460.175	0.105
1782	2.27	0.055	9610.2	0.105
1783	4.002	0.052	16059.7	0.105
1784	4.802	0.0613	16293.7	0.105
1785	5.936	0.0748	16639.8	0.105
1786	6.155	0.0792	16307.5	0.105
1787	6.523	0.0831	16464.2	0.105
1788	6.474	0.0841	16094.6	0.105
1789	6.099	0.0773	16549.5	0.105
1790	7.792	0.2187	13128.665	0.105
1791	7.057	0.0891	16575.5	0.105
1792	5.577	0.0708	16500.9	0.105
1793	4.993	0.0645	16021.9	0.105
1794	3.623	0.0515	14162.3	0.105
1795	2.252	0.0414	10301.4	0.105
1796	5.003	0.0729	13658.9	0.105
1797	7.059	0.0893	16581.7	0.105
1798	5.967	0.0758	16504.7	0.105
1799	5.476	0.0698	16471.5	0.105
1800	3.813	0.0483	16607.4	0.105
1801	3.748	0.0481	16408.3	0.105
1802	3.704	0.0526	14046.1	0.105
1803	1.085	0.3753	3008.9	0.105
1804				
1805				
1806				

	K	L	M	N
1807	3.263	0.3022	4171.175	0.105
1808	2.996	0.0541	11268.5	0.105
1809	1.954	0.0462	8765.1	0.105
1810	5.106	0.0685	15339.3	0.105
1811	5.702	0.0721	16510	0.105
1812	5.374	0.07	15435.6	0.105
1813	4.86	0.0636	14971.1	0.105
1814	6.352	0.0765	17390.1	0.105
1815	4.626	0.0626	15083.7	0.105
1816	1.785	0.033	10290.6	0.105
1817	6.521	0.0787	17238.7	0.105
1818	6.736	0.0794	17768.6	0.105
1819	7.034	0.083	17779.8	0.105
1820	6.207	0.0789	15991.6	0.105
1821	5.648	0.0705	16047.7	0.105
1822	6.218	0.0742	17536.3	0.105
1823	6.15	0.076	16880.2	0.105
1824	4.685	0.0614	15324.2	0.105
1825	4.787	0.0623	15507.8	0.105
1826	4.418	0.0578	15342.1	0.105
1827	5.362	0.066	16959.1	0.105
1828	4.571	0.0587	16039.8	0.105
1829	4.463	0.0582	15837.4	0.105
1830	3.627	0.0484	14808.2	0.105
1831	4.39	0.0532	17288.4	0.105
1832	4.704	0.0566	17452.3	0.105
1833	4.28	0.0513	17485.3	0.105
1834	4.603	0.0555	17379.3	0.105
1835	4.617	0.0568	16933.3	0.105
1836	1.33	0.0283	9554.8	0.105
1837	3.047	0.0444	12706.3	0.105
1838	5.535	0.0674	17153.7	0.105
1839	5.397	0.0655	17229.7	0.105
1840	5.424	0.0655	17402.7	0.105
1841	4.949	0.0613	16792.5	0.105
1842	3.135	0.0462	13279.8	0.105
1843	4.596	0.0562	17156.2	0.105
1844	1.764	0.0326	10425.2	0.105
1845	4.018	0.0553	13999.1	0.105
1846	6.016	0.0742	17005.3	0.105
1847	5.668	0.0685	17372.5	0.105
1848	5.405	0.0645	17582.9	0.105
1849	14.881	0.1848	16572.7	0.105

	K	L	M	N
1850	3.999	0.0522	15116.9	0.105
1851	3.914	0.0525	14090	0.105
1852	5.343	0.0672	16089.8	0.105
1853	5.675	0.069	17219.9	0.105
1854	5.145	0.0664	15799.2	0.105
1855	5.739	0.0579	21058.6	0.105
1856	4.314	0.0398	22762.4	0.105
1857	1.935	0.0213	18714.3	0.105
1858	2.612	0.0278	19092.9	0.105
1859	5.405	0.0502	22306.4	0.105
1860	5.7	0.0568	21076.7	0.105
1861	5.528	0.0644	17787.8	0.105
1862	5.094	0.062	16768.8	0.105
1863	2.849	0.039	14110.9	0.105
1864	4.783	0.054	18593.8	0.105
1865	4.302	0.0538	16479	0.105
1866	5.718	0.0656	18297.5	0.105
1867	5.563	0.0625	18666.3	0.105
1868	5.842	0.0652	18774.5	0.105
1869	4.994	0.0593	17112.4	0.105
1870	5.41	0.0652	16998	0.105
1871	7.458	0.0851	18370	0.105
1872	8.891	0.1007	18520.9	0.105
1873	8.033	0.0929	18128.3	0.105
1874	6.4	0.0761	17603.8	0.105
1875	2.155	0.0334	10877.4	0.105
1876	5.601	0.0645	18200.6	0.105
1877	6.988	0.0799	18340.1	0.105
1878	7.374	0.0838	18413.8	0.105
1879	7.193	0.0845	17843.7	0.105
1880	6.834	0.0799	17918.9	0.105
1881	6.499	0.0745	18266	0.105
1882	5.13	0.0595	18075.5	0.105
1883	5.493	0.0628	18361.8	0.105
1884	4.112	0.0862	10096.9	0.105
1885	2.137	0.1349	4162.084	0.105
1886				
1887				
1888				
1889				
1890				
1891				
1892				

	K	L	M	N
1893	5.719	2.9213	417.89	0.105
1894	0.893	0.0468	4140.897	0.105
1895	2.918	0.0438	13417.8	0.105
1896	2.486	0.0498	10415.2	0.105
1897	4.848	0.0718	13761.8	0.105
1898	3.131	0.063	10424.9	0.105
1899	3.006	0.0545	11344.5	0.105
1900	2.305	0.0462	10437.2	0.105
1901	2.19	0.044	10430.9	0.105
1902	1.653	0.035	9907.6	0.105
1903	1.582	0.0319	10402.1	0.105
1904	1.739	0.0318	10629.8	0.105
1905	0.033	1.68	4.158	0.105
1906				
1907				
1908				
1909				
1910				
1911				
1912				
1913				
1914				
1915				
1916				
1917				

	O	P	Q	R
1	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Primary Fuel Type
2				Coal
3				Coal
4				Coal
5				Coal
6				Coal
7				Coal
8				Coal
9				Coal
10				Coal
11				Coal
12				Coal
13				Coal
14				Coal
15				Coal
16				Coal
17				Coal
18				Coal
19				Coal
20				Coal
21				Coal
22				Coal
23				Coal
24				Coal
25				Coal
26				Coal
27				Coal
28				Coal
29				Coal
30				Coal
31				Coal
32				Coal
33				Coal
34				Coal
35				Coal
36				Coal
37				Coal
38				Coal
39				Coal
40				Coal
41				Coal
42				Coal
43				Coal

	O	P	Q	R
44				Coal
45				Coal
46				Coal
47				Coal
48				Coal
49				Coal
50				Coal
51				Coal
52				Coal
53				Coal
54				Coal
55				Coal
56				Coal
57				Coal
58				Coal
59				Coal
60				Coal
61				Coal
62				Coal
63				Coal
64				Coal
65				Coal
66				Coal
67				Coal
68				Coal
69				Coal
70				Coal
71				Coal
72				Coal
73				Coal
74				Coal
75				Coal
76				Coal
77				Coal
78				Coal
79				Coal
80				Coal
81				Coal
82				Coal
83				Coal
84				Coal
85				Coal
86				Coal

	O	P	Q	R
87				Coal
88				Coal
89				Coal
90				Coal
91				Coal
92	8.092	0.1344	117877.4	Coal
93	7	0.1613	86950.5	Coal
94	6.448	0.1331	97087.2	Coal
95	10.328	0.1533	129732.2	Coal
96	8.174	0.1362	116533.1	Coal
97	9.888	0.1488	130675.9	Coal
98	13.208	0.1635	160252.3	Coal
99	10.843	0.1551	136050.9	Coal
100	10.863	0.1578	134350.7	Coal
101	9.449	0.1588	117268	Coal
102	13.083	0.171	150712.9	Coal
103	11.331	0.1546	142300.5	Coal
104	8.487	0.1515	107187.1	Coal
105	11.548	0.1561	143419.9	Coal
106	7.422	0.136	108007	Coal
107	6.779	0.1465	89445.6	Coal
108	6.231	0.1432	85571.3	Coal
109	8.58	0.1598	105164.8	Coal
110	11.942	0.1798	132852.5	Coal
111	10.6	0.1885	114551.4	Coal
112	8.989	0.1654	108049.5	Coal
113	4.438	0.1496	58441.6	Coal
114	9.45	0.1701	106593.9	Coal
115	13.921	0.1812	153213.1	Coal
116	14.953	0.1815	164310	Coal
117	15.668	0.1847	169754.5	Coal
118	13.92	0.17	163092.1	Coal
119	11.361	0.1514	145223.6	Coal
120	12.923	0.162	158307.3	Coal
121	7.033	0.1273	109884.3	Coal
122	8.669	0.1303	130558.3	Coal
123	13.155	0.1612	162548.4	Coal
124	9.456	0.1512	124199.8	Coal
125	9.87	0.1453	132883.3	Coal
126	6.595	0.1221	107403.1	Coal
127	7.275	0.1322	107729.6	Coal
128	7.581	0.1354	108606.6	Coal
129	11.965	0.1655	142711.1	Coal

	O	P	Q	R
130	13.764	0.1744	158273.2	Coal
131	14.749	0.1791	164715	Coal
132	14.9	0.1797	165827.8	Coal
133	14.701	0.18	163339.1	Coal
134	15.045	0.18	167171.1	Coal
135	12.681	0.1864	146644.93	Coal
136				Coal
137				Coal
138				Coal
139				Coal
140				Coal
141				Coal
142				Coal
143	5.882	0.438	26858.145	Coal
144	8.534	0.1921	97820.7	Coal
145	12.343	0.1822	133941.1	Coal
146	16.66	0.2002	166369	Coal
147	12.508	0.1816	134967.2	Coal
148	10.361	0.1699	117724.6	Coal
149	12.688	0.1771	142081.3	Coal
150	11.637	0.1683	136017.4	Coal
151	13.101	0.23	131760.969	Coal
152	14.288	0.1757	162754.1	Coal
153	14.234	0.1683	169143.6	Coal
154	14.532	0.1731	167903.9	Coal
155	12.049	0.1574	150927.2	Coal
156	7.659	0.1458	104188.2	Coal
157	11.29	0.1562	143263.7	Coal
158	13.9	0.1674	166052.4	Coal
159	14.171	0.1702	166571.7	Coal
160	14.378	0.1723	166859.8	Coal
161	14.644	0.175	167323.8	Coal
162	14.011	0.1672	167584.6	Coal
163	13.524	0.1635	165357.5	Coal
164	13.387	0.1626	164718.2	Coal
165	13.59	0.1679	160970	Coal
166	14.644	0.1807	162061.9	Coal
167	14.115	0.1795	157241.1	Coal
168	12.358	0.1635	150714.7	Coal
169	12.538	0.1668	149126.1	Coal
170	6.647	0.1342	98343.9	Coal
171	7.528	0.1444	102867.5	Coal
172	11.944	0.1658	142855.2	Coal

	O	P	Q	R
173	12.942	0.1778	145166.9	Coal
174	10.643	0.1568	134617.6	Coal
175	10.764	0.153	139104.1	Coal
176	8.065	0.1374	114068.3	Coal
177	6.092	0.1247	97205.4	Coal
178	9.064	0.1481	119074.5	Coal
179	12.394	0.1673	146146.8	Coal
180	13.913	0.1778	156474.9	Coal
181	13.882	0.1775	156418	Coal
182	13.297	0.1729	153802.5	Coal
183	11.506	0.1606	143476	Coal
184	0.353	0.339	2283.668	Coal
185				Coal
186				Coal
187				Coal
188				Coal
189				Coal
190				Coal
191				Coal
192				Coal
193				Coal
194				Coal
195				Coal
196				Coal
197				Coal
198				Coal
199				Coal
200				Coal
201				Coal
202				Coal
203				Coal
204				Coal
205				Coal
206				Coal
207				Coal
208				Coal
209				Coal
210				Coal
211				Coal
212				Coal
213				Coal
214				Coal
215				Coal

	O	P	Q	R
216				Coal
217				Coal
218				Coal
219				Coal
220				Coal
221				Coal
222				Coal
223				Coal
224				Coal
225				Coal
226				Coal
227				Coal
228				Coal
229				Coal
230				Coal
231				Coal
232				Coal
233				Coal
234				Coal
235				Coal
236				Coal
237				Coal
238				Coal
239				Coal
240				Coal
241				Coal
242				Coal
243				Coal
244				Coal
245				Coal
246				Coal
247				Coal
248				Coal
249				Coal
250				Coal
251				Coal
252				Coal
253				Coal
254	2.823	0.438	12889.34	Coal
255	9.496	0.438	43362.54	Coal
256				Coal
257	17.547	0.3767	94564.1	Coal
258	9.301	0.1902	103687.25	Coal

	O	P	Q	R
259				Coal
260				Coal
261				Coal
262				Coal
263				Coal
264				Coal
265				Coal
266				Coal
267				Coal
268	7.955	0.3778	47581.48	Coal
269	12.09	0.1648	144044.3	Coal
270	14.322	0.1736	162564.2	Coal
271	16.172	0.1808	178793.8	Coal
272	13.181	0.1728	150759.6	Coal
273	11.646	0.1763	131617.5	Coal
274	11.273	0.1754	127922.4	Coal
275	12.888	0.1779	143920.7	Coal
276	12.191	0.1795	135105.5	Coal
277	13.685	0.1763	154820.8	Coal
278	16.381	0.1843	177726.1	Coal
279	16.121	0.183	176145.7	Coal
280	16.912	0.1873	180586.6	Coal
281	17.891	0.1976	181106.3	Coal
282	14.876	0.1883	157889.1	Coal
283	13.517	0.1829	147188.9	Coal
284	13.293	0.1842	143933.3	Coal
285	12.856	0.1829	139606	Coal
286	15.249	0.1901	159950.6	Coal
287	17.121	0.1919	178522.7	Coal
288	16.158	0.1926	167761.8	Coal
289	16.859	0.1915	176103.1	Coal
290	18.35	0.2013	182312.5	Coal
291	16.57	0.1903	173899	Coal
292	15.519	0.1896	163270.4	Coal
293	16.901	0.1913	176721.2	Coal
294	17.496	0.191	183202.5	Coal
295	17.378	0.1913	181732.5	Coal
296	17.406	0.191	182265.6	Coal
297	17.339	0.191	181560.5	Coal
298	18.264	0.2013	181465.5	Coal
299	17.192	0.191	180023.8	Coal
300	18.134	0.2013	180092.7	Coal
301	17.233	0.191	180448	Coal

	O	P	Q	R
302	17.207	0.191	180173.1	Coal
303	15.758	0.1892	166006.4	Coal
304	18.487	0.2131	171125.1	Coal
305	21.845	0.228	191624	Coal
306	21.817	0.228	191378.5	Coal
307	21.623	0.228	189673.7	Coal
308	21.477	0.228	188391.1	Coal
309	21.318	0.2277	187244.4	Coal
310	21.009	0.2273	184783.9	Coal
311	19.89	0.2238	177406.9	Coal
312	22.647	0.2368	191308.4	Coal
313	21.802	0.228	191249.4	Coal
314	21.5	0.228	188599.6	Coal
315	21.23	0.228	186225.1	Coal
316	22.283	0.2368	188204.9	Coal
317	21.57	0.228	189208.5	Coal
318	21.402	0.2277	187971.6	Coal
319	18.153	0.198	182142.9	Coal
320	15.253	0.1744	174771	Coal
321	16.024	0.1784	179671.6	Coal
322	15.667	0.175	179089.5	Coal
323	15.608	0.1769	176435.4	Coal
324	15.078	0.1785	168642.2	Coal
325	9.758	0.1459	129511.5	Coal
326	15.67	0.1785	175555.5	Coal
327	15.92	0.1777	179218.3	Coal
328	7.407	0.1819	85512.275	Coal
329				Coal
330				Coal
331	10.003	0.2666	80263.226	Coal
332	16.24	0.1814	179100.7	Coal
333	15.481	0.1778	173956.8	Coal
334	14.592	0.1717	169552.8	Coal
335	15.351	0.1751	175308.9	Coal
336	15.592	0.1765	176623.9	Coal
337	15.239	0.1729	176292.3	Coal
338	15.432	0.1739	177467.9	Coal
339	15.299	0.1721	177705.5	Coal
340	14.684	0.1699	172487.4	Coal
341	15.285	0.172	177669.2	Coal
342	14.365	0.163	176141.4	Coal
343	15.201	0.1694	179503.4	Coal
344	14.31	0.1633	175035	Coal

	O	P	Q	R
345	14.513	0.167	173467.3	Coal
346	14.052	0.1664	168469.7	Coal
347	14.849	0.1697	174716	Coal
348	14.616	0.1686	173271.6	Coal
349	13.129	0.1676	156454.6	Coal
350	0.001	0.242	11.844	Coal
351				Coal
352	6.395	0.357	34384.529	Coal
353				Coal
354				Coal
355				Coal
356	10.942	0.2679	92956.7	Coal
357	15.179	0.17	178526.9	Coal
358	15.167	0.1704	178044	Coal
359	15.167	0.171	177390.8	Coal
360	14.71	0.1674	175604	Coal
361	14.689	0.1694	173305.6	Coal
362	14.82	0.1692	175212.3	Coal
363	14.909	0.1704	174976.6	Coal
364	15.154	0.1735	174262.3	Coal
365	14.979	0.1693	176922.3	Coal
366	14.975	0.1697	176527.2	Coal
367	15.05	0.1709	176150.4	Coal
368	14.868	0.1686	176349.7	Coal
369	14.4	0.1632	176468.8	Coal
370	14.517	0.1665	174415.4	Coal
371	11.898	0.171	140333.221	Coal
372				Coal
373	11.295	0.2516	101100.38	Coal
374	10.687	0.1512	138732.9	Coal
375	14.509	0.1652	175635.3	Coal
376	14.677	0.1668	175947.9	Coal
377	14.675	0.1676	175064.4	Coal
378	15.031	0.1719	174925.3	Coal
379	14.368	0.1635	175729.2	Coal
380	14.718	0.1817	162768.2	Coal
381	13.425	0.1721	156054.5	Coal
382	14.965	0.1707	175280.3	Coal
383	14.642	0.1659	176485.2	Coal
384	14.76	0.1685	175194.4	Coal
385	14.183	0.1637	173053.2	Coal
386	14.334	0.1642	174548.9	Coal
387	14.26	0.1631	174847.8	Coal

	O	P	Q	R
388	14.423	0.1644	175381.7	Coal
389	14.76	0.1683	175344.6	Coal
390	13.872	0.1647	168252.2	Coal
391	13.742	0.1606	170955.7	Coal
392	14.066	0.1614	174331.6	Coal
393	13.49	0.157	171765.1	Coal
394	14.138	0.1599	176864.6	Coal
395	14.559	0.1656	175823.3	Coal
396	14.293	0.1634	174906.8	Coal
397	14.741	0.1669	176629	Coal
398	15.641	0.1762	177535.5	Coal
399	15.244	0.1745	174709.9	Coal
400	14.158	0.1601	176870.2	Coal
401	14.236	0.1613	176569.7	Coal
402	14.039	0.1604	174993.5	Coal
403	14.135	0.1604	176229.9	Coal
404	14.299	0.1709	166557.8	Coal
405	11.148	0.1569	139347.9	Coal
406	12.638	0.1608	154632.9	Coal
407	13.979	0.1632	171315.2	Coal
408	13.225	0.1521	173915.9	Coal
409	9.594	0.1415	133836.5	Coal
410	13.461	0.1581	169966.4	Coal
411	13.707	0.1602	170974.4	Coal
412	14.361	0.164	175080.1	Coal
413	12.917	0.158	162370.4	Coal
414	0.266	0.32	1188.7	Coal
415				Coal
416				Coal
417				Coal
418	7.276	0.438	33225.39	Coal
419	10.708	0.438	48894.648	Coal
420				Coal
421				Coal
422				Coal
423				Coal
424				Coal
425				Coal
426				Coal
427				Coal
428				Coal
429				Coal
430				Coal

	O	P	Q	R
431				Coal
432				Coal
433				Coal
434				Coal
435				Coal
436				Coal
437				Coal
438				Coal
439				Coal
440				Coal
441				Coal
442				Coal
443				Coal
444				Coal
445				Coal
446				Coal
447	4.689	0.438	21411.918	Coal
448	15.616	0.2983	108932.6	Coal
449	7.114	0.1449	97960.8	Coal
450	9.859	0.154	122992.2	Coal
451	9.148	0.1573	113716.3	Coal
452	15.506	0.1796	172626.7	Coal
453	15.513	0.177	175259.1	Coal
454	14.598	0.1738	167986.5	Coal
455	15.025	0.1722	174502.4	Coal
456	14.552	0.1693	171532.2	Coal
457	11.016	0.1713	128466.752	Coal
458				Coal
459				Coal
460				Coal
461				Coal
462	10.726	0.438	48975.885	Coal
463				Coal
464	0.821	0.438	3749.535	Coal
465	10.447	0.2128	100423.3	Coal
466	13.278	0.1628	162189.3	Coal
467	14.242	0.1675	169774.8	Coal
468	10.989	0.1541	139586.3	Coal
469	14.809	0.1704	173880.7	Coal
470	14.13	0.1676	168416.8	Coal
471	14.619	0.1684	173624.5	Coal
472	14.733	0.1687	174652	Coal
473	13.658	0.164	163752.5	Coal

	O	P	Q	R
474	8.597	0.1467	113778.4	Coal
475	14.866	0.1701	174812.7	Coal
476	11.207	0.1575	139709.9	Coal
477	11.159	0.1678	135834.9	Coal
478	0.018	0.16	227.52	Coal
479	1.362	0.438	6217.458	Coal
480	14.544	0.2308	138274.2	Coal
481	13.81	0.1673	164904.3	Coal
482	14.568	0.1694	172012.1	Coal
483	14.75	0.1705	173051.9	Coal
484	14.25	0.168	169316.1	Coal
485	14.379	0.1673	171896.8	Coal
486	12.88	0.1598	159916.1	Coal
487	11.443	0.1592	142803.4	Coal
488	13.271	0.1632	161519.5	Coal
489	14.652	0.1675	174856.7	Coal
490	15.162	0.1699	178452.3	Coal
491	15.154	0.1691	179062.8	Coal
492	12.738	0.1615	156378.5	Coal
493	12.998	0.1598	159001.8	Coal
494	12.509	0.1596	153401	Coal
495	14.558	0.1694	171570.6	Coal
496	13.261	0.1633	161548.3	Coal
497	11.8	0.1593	147595.2	Coal
498	15.175	0.1723	176089.8	Coal
499	14.718	0.1705	171962.1	Coal
500	11.721	0.1574	144773.7	Coal
501	10.378	0.147	138260.7	Coal
502	7.465	0.1274	113696.8	Coal
503	8.783	0.1334	129619.3	Coal
504	8.188	0.1365	116496.9	Coal
505	11.608	0.1534	148840.8	Coal
506	8.631	0.155	111881.2	Coal
507	6.846	0.1223	109353.8	Coal
508	13.261	0.158	165445.4	Coal
509	11.852	0.17	141269.74	Coal
510				Coal
511	13.007	0.3513	78820.216	Coal
512	12.717	0.1568	161477.6	Coal
513	14.082	0.1662	169489.2	Coal
514	12.923	0.1845	151575.662	Coal
515	9.704	0.1706	119731.2	Coal
516	11.837	0.1503	156227.5	Coal

	O	P	Q	R
517	14.297	0.1623	176077.5	Coal
518	11.23	0.1439	155059.9	Coal
519	13.974	0.16	174545.1	Coal
520	14.319	0.164	174681.4	Coal
521	12.99	0.1585	162322.1	Coal
522	12.332	0.1568	155676.9	Coal
523	10.606	0.1504	137242	Coal
524	12.602	0.1653	151766.4	Coal
525	13.278	0.1654	158756.2	Coal
526	12.172	0.161	148598.7	Coal
527	9.26	0.1508	123689.6	Coal
528	8.91	0.1387	127032	Coal
529	13.238	0.1575	164773	Coal
530	10.459	0.1395	144368.8	Coal
531	10.193	0.1428	138155.7	Coal
532	13.735	0.1618	169534.9	Coal
533	14.834	0.1683	176354.7	Coal
534	11.746	0.1523	150822	Coal
535	8.822	0.14	122533.3	Coal
536	15.048	0.1688	178307.3	Coal
537	14.839	0.1695	175101.5	Coal
538	12.369	0.1619	151340.5	Coal
539	13.704	0.1666	163532.1	Coal
540	12.83	0.1715	153291.967	Coal
541				Coal
542	9.304	0.2132	92832.95	Coal
543	13.381	0.1598	165034.6	Coal
544	14.679	0.172	170457.7	Coal
545	12.341	0.163	149622.4	Coal
546	14.353	0.173	164453	Coal
547	13.958	0.1733	161050.9	Coal
548	9.198	0.1369	130113	Coal
549	10.463	0.2463	97050.987	Coal
550	6.981	0.1212	116312.3	Coal
551	11.584	0.1537	150346.1	Coal
552	10.629	0.1476	143558.1	Coal
553	8.251	0.133	123787.5	Coal
554	7.798	0.1384	113809.9	Coal
555	7.478	0.1325	113170.2	Coal
556	7.683	0.1309	117294.2	Coal
557	9.645	0.149	129004.3	Coal
558	13.277	0.1661	159575.7	Coal
559	15.106	0.1728	174753.3	Coal

	O	P	Q	R
560	13.865	0.1655	167685.9	Coal
561	13.558	0.158	171567	Coal
562	12.648	0.1614	156898.7	Coal
563	11.218	0.1498	147982	Coal
564	14.22	0.1693	167927.6	Coal
565	14.03	0.1668	168119.9	Coal
566	14.532	0.1695	171392.7	Coal
567	14.362	0.1675	171243.4	Coal
568	14.947	0.1712	174545.2	Coal
569	13.799	0.1629	168783.6	Coal
570	0.395	0.225	6111.65	Coal
571				Coal
572				Coal
573				Coal
574				Coal
575				Coal
576				Coal
577				Coal
578				Coal
579				Coal
580				Coal
581				Coal
582				Coal
583				Coal
584				Coal
585				Coal
586				Coal
587				Coal
588				Coal
589				Coal
590				Coal
591				Coal
592				Coal
593				Coal
594				Coal
595				Coal
596				Coal
597				Coal
598				Coal
599				Coal
600				Coal
601				Coal
602				Coal

	O	P	Q	R
603				Coal
604				Coal
605				Coal
606				Coal
607				Coal
608				Coal
609				Coal
610				Coal
611				Coal
612				Coal
613				Coal
614				Coal
615				Coal
616				Coal
617				Coal
618				Coal
619				Coal
620				Coal
621				Coal
622				Coal
623				Coal
624				Coal
625				Coal
626				Coal
627				Coal
628				Coal
629				Coal
630				Coal
631				Coal
632				Coal
633				Coal
634				Coal
635				Coal
636				Coal
637				Coal
638				Coal
639				Coal
640				Coal
641				Coal
642				Coal
643				Coal
644				Coal
645				Coal

	O	P	Q	R
646	5.237	0.438	23914.92	Coal
647	19.352	0.3874	98558.5	Coal
648	8.186	0.1443	112979.4	Coal
649	10.318	0.1437	139841.1	Coal
650	9.074	0.1408	125436.9	Coal
651	10.864	0.1533	136645.6	Coal
652	9.263	0.1546	119331.3	Coal
653	8.849	0.1551	112782.8	Coal
654	7.49	0.1593	94736.5	Coal
655	12.071	0.1625	146249.5	Coal
656	15.295	0.1723	177476.7	Coal
657	15.523	0.1785	173660.4	Coal
658	14.701	0.1715	171451.2	Coal
659	12.379	0.1568	155988.4	Coal
660	14.383	0.1675	171702.4	Coal
661	15.422	0.1715	179901.1	Coal
662	15.652	0.1705	183568.6	Coal
663	15.677	0.1719	182369.5	Coal
664	16.514	0.1827	180796.8	Coal
665	15.771	0.175	180291.4	Coal
666	15.901	0.1794	177342.4	Coal
667	15.347	0.1786	171628.9	Coal
668	15.688	0.1798	174479.4	Coal
669	15.395	0.1756	175369.6	Coal
670	14.728	0.1719	171219.5	Coal
671	14.889	0.1708	174167.9	Coal
672	14.86	0.169	175391.4	Coal
673	16.012	0.1783	179526.1	Coal
674	16.212	0.1795	180659.7	Coal
675	15.997	0.1793	178496.1	Coal
676	14.597	0.176	165980.5	Coal
677	15.999	0.1795	178157.4	Coal
678	15.537	0.1744	178210.7	Coal
679	14.897	0.1709	174466.9	Coal
680	14.502	0.1696	170957.6	Coal
681	15.325	0.1804	169573.7	Coal
682	15.155	0.1746	173593.6	Coal
683	15.822	0.178	177794.9	Coal
684	15.016	0.17	176764.1	Coal
685	13.83	0.1754	157356.9	Coal
686	9.1	0.1749	114643.55	Coal
687				Coal
688	3.513	0.438	16043.225	Coal

	O	P	Q	R
689	36.715	0.438	167647.4	Coal
690	25.149	0.2821	172178.8	Coal
691	15.096	0.1694	178196.2	Coal
692	16.458	0.184	178896.4	Coal
693	16.028	0.1799	178204.7	Coal
694	15.336	0.2339	146574.46	Coal
695	5.914	0.4158	28847.024	Coal
696	11.612	0.2736	91753.64	Coal
697	14.07	0.1751	160452.5	Coal
698	15.911	0.1793	177534.2	Coal
699	16.033	0.18	178170.6	Coal
700	15.547	0.175	177710.9	Coal
701	16.233	0.1818	178575.9	Coal
702	15.84	0.178	177883.5	Coal
703	15.791	0.1777	177678.5	Coal
704	15.834	0.1791	176798.4	Coal
705	16.023	0.1823	175743.9	Coal
706	14.605	0.172	168977.9	Coal
707	16.245	0.1835	177060.9	Coal
708	15.933	0.1795	177565.5	Coal
709	16.024	0.1796	178406.7	Coal
710	15.77	0.1755	179669.5	Coal
711	15.996	0.1797	178049.3	Coal
712	15.906	0.1814	175355.2	Coal
713	15.285	0.1774	172175.6	Coal
714	14.672	0.1735	168852.9	Coal
715	14.782	0.1698	173948.7	Coal
716	16.351	0.1833	178315.1	Coal
717	16.314	0.1805	180657.9	Coal
718	16.008	0.1783	179615.3	Coal
719	16.117	0.1791	179936	Coal
720	15.768	0.1735	181713.8	Coal
721	14.807	0.1693	174504.5	Coal
722	16.537	0.1802	183380.1	Coal
723	16.642	0.18	184860.2	Coal
724	16.735	0.1798	186161.4	Coal
725	17.063	0.1828	186670.2	Coal
726	16.98	0.1818	186775.9	Coal
727	16.459	0.1779	184871.3	Coal
728	15.11	0.1759	171372.1	Coal
729	16.327	0.1794	182066.6	Coal
730	16.233	0.1815	178886.9	Coal
731	16.223	0.1815	178815.4	Coal

	O	P	Q	R
732	16.372	0.1807	181192.6	Coal
733	16.441	0.181	181635.1	Coal
734	16.478	0.1816	181451.8	Coal
735	16.841	0.184	182996.4	Coal
736	16.069	0.1774	181191.9	Coal
737	16.254	0.179	181592.6	Coal
738	16.404	0.1804	181875.7	Coal
739	15.811	0.1769	178582	Coal
740	14.838	0.1681	176492.9	Coal
741	16.146	0.1793	180051.5	Coal
742	16.555	0.1843	179620	Coal
743	16.854	0.1875	179779.5	Coal
744	16.679	0.1855	179806.9	Coal
745	16.363	0.1823	179485.5	Coal
746	16.377	0.1823	179686.2	Coal
747	16.77	0.1866	179713.2	Coal
748	16.697	0.1851	180387.4	Coal
749	16.039	0.1815	176566.5	Coal
750	15.983	0.1831	174407.8	Coal
751	16.41	0.1835	178915.1	Coal
752	16.155	0.1808	178570.4	Coal
753	15.896	0.1807	175904.6	Coal
754	16.034	0.184	174035.7	Coal
755	15.702	0.1819	172595.9	Coal
756	16.476	0.1849	178208.9	Coal
757	16.255	0.1807	179859.4	Coal
758	16.585	0.1828	181482.4	Coal
759	14.638	0.1814	161161.6	Coal
760	16.375	0.1858	176026.2	Coal
761	16.872	0.1868	180644.7	Coal
762	16.167	0.1808	178892	Coal
763	16.845	0.1865	180646	Coal
764	17.071	0.1999	170967.7	Coal
765	15.36	0.1845	166412.3	Coal
766	16.096	0.1857	173236.6	Coal
767	15.744	0.1813	173553.5	Coal
768	17.076	0.1916	178276.5	Coal
769	15.96	0.1824	175232.9	Coal
770	16.732	0.1863	179644.3	Coal
771	12.844	0.1993	134103.65	Coal
772				Coal
773				Coal
774				Coal

	O	P	Q	R
775				Coal
776				Coal
777				Coal
778				Coal
779	5.831	0.438	26625.3	Coal
780	18.126	0.3412	113222.7	Coal
781	16.101	0.1812	177703.7	Coal
782	15.752	0.1805	174498.9	Coal
783	15.892	0.181	175560.8	Coal
784	15.88	0.1778	178592.7	Coal
785	13.819	0.1944	158032.2	Coal
786				Coal
787				Coal
788				Coal
789				Coal
790				Coal
791				Coal
792	15.454	0.3962	77599.94	Coal
793	14.925	0.1814	164355.3	Coal
794	15.859	0.1817	174631.5	Coal
795	16.498	0.1828	180470.3	Coal
796	15.994	0.1768	180934.5	Coal
797	10.402	0.2122	106222.172	Coal
798				Coal
799				Coal
800				Coal
801	12.557	0.3999	63194.74	Coal
802	14.253	0.1708	166353.3	Coal
803	15.868	0.1758	180571.4	Coal
804	15.678	0.1735	180681.3	Coal
805	15.848	0.1757	180383.5	Coal
806	15.505	0.1724	179859.7	Coal
807	15.638	0.1748	178705.1	Coal
808	16.691	0.1931	173363.6	Coal
809	16.111	0.2025	161387.7	Coal
810	18.169	0.2135	169358.9	Coal
811	15.679	0.1796	174577.4	Coal
812	15.723	0.1767	177999.5	Coal
813	15.962	0.1799	177431.9	Coal
814	16.219	0.1863	174175.1	Coal
815	15.798	0.1855	170362.5	Coal
816	14.76	0.1756	168021.9	Coal
817	14.479	0.178	162200	Coal

	O	P	Q	R
818	0.384	0.348	3722.802	Coal
819				Coal
820				Coal
821	6.595	0.2929	56517.888	Coal
822	15.279	0.1808	169005.2	Coal
823	15.511	0.1839	168710.6	Coal
824	15.394	0.1818	169309.2	Coal
825	15.051	0.1774	169672.4	Coal
826	15.071	0.1773	169998.6	Coal
827	15.348	0.1806	169994.7	Coal
828	13.4	0.1853	148807.98	Coal
829				Coal
830	3.932	0.438	17956.066	Coal
831	15.553	0.2123	152990.8	Coal
832	15.636	0.1851	168960	Coal
833	15.268	0.1807	168975.5	Coal
834	15.605	0.1839	169694.4	Coal
835	15.071	0.1821	165538.8	Coal
836	15.089	0.1807	166998.6	Coal
837	15.263	0.1816	168072.4	Coal
838	15.464	0.183	169046.6	Coal
839	15.201	0.1833	165845.3	Coal
840	14.971	0.1813	165162	Coal
841	15.265	0.1803	169383.6	Coal
842	15.173	0.1793	169243.9	Coal
843	15.5	0.1847	167898.4	Coal
844	15.233	0.1823	167084.9	Coal
845	15.34	0.1818	168724.1	Coal
846	15.32	0.1803	169914.9	Coal
847	15.281	0.1796	170179.1	Coal
848	15.657	0.1832	170919	Coal
849	15.442	0.1809	170745.8	Coal
850	15.501	0.183	169446.5	Coal
851	15.208	0.1808	168195.3	Coal
852	14.913	0.1766	168897.2	Coal
853	14.796	0.1733	170795.8	Coal
854	15.565	0.1811	171862.6	Coal
855	14.976	0.1759	170336.8	Coal
856	15.089	0.1777	169874.3	Coal
857	14.754	0.177	166609.4	Coal
858	14.231	0.1736	163429.1	Coal
859	15.072	0.1795	167970.6	Coal
860	15.43	0.1858	166080.7	Coal

	O	P	Q	R
861	14.128	0.1663	169939.3	Coal
862	14.246	0.167	170610.4	Coal
863	14.696	0.173	169867.7	Coal
864	15.113	0.1768	170927.8	Coal
865	15.225	0.1768	172240.8	Coal
866	15.098	0.1758	171809.5	Coal
867	15.313	0.1797	170418.9	Coal
868	14.88	0.1744	170623	Coal
869	14.744	0.1747	168807.9	Coal
870	15.023	0.179	167865.5	Coal
871	12.884	0.1648	152833.2	Coal
872	14.425	0.1709	168810.3	Coal
873	14.904	0.1741	171141.2	Coal
874	14.736	0.1712	172150.9	Coal
875	15.065	0.1777	169546.9	Coal
876	16.218	0.1882	172385.4	Coal
877	15.759	0.1826	172579.2	Coal
878	16.269	0.1891	172102.4	Coal
879	16.209	0.189	171566.1	Coal
880	15.399	0.1806	170464.9	Coal
881	15.325	0.1767	173495.3	Coal
882	15.13	0.1744	173538.4	Coal
883	15.442	0.1774	174070.8	Coal
884	15.247	0.1756	173630.2	Coal
885	15.013	0.1732	173356.1	Coal
886	15.461	0.1792	172555.7	Coal
887	14.985	0.1725	173744.4	Coal
888	14.924	0.1715	174001.5	Coal
889	14.613	0.1678	174218.9	Coal
890	15.301	0.1746	175290.1	Coal
891	15.705	0.1795	174993.5	Coal
892	15.442	0.177	174523.2	Coal
893	15.766	0.1831	172210.6	Coal
894	15.735	0.181	173912.6	Coal
895	15.464	0.1772	174580.3	Coal
896	15.165	0.1774	170893.3	Coal
897	15.168	0.1777	170400.1	Coal
898	15.019	0.174	172481.6	Coal
899	15.379	0.1765	174282.3	Coal
900	15.247	0.1761	173144	Coal
901	14.803	0.17	174154.3	Coal
902	14.689	0.1716	171123.4	Coal
903	12.419	0.1727	144326.9	Coal

	O	P	Q	R
904				Coal
905	3.782	0.3499	27520.08	Coal
906	1.571	0.1848	17840.494	Coal
907	10.57	0.2383	112138.1	Coal
908	15.578	0.1765	176481.9	Coal
909	15.275	0.1742	175349.7	Coal
910	15.205	0.1741	174699.5	Coal
911	15.4	0.1755	175505.2	Coal
912	14.657	0.1729	169185.2	Coal
913	15.071	0.175	172385.7	Coal
914	15.424	0.1755	175744	Coal
915	15.331	0.1741	176093.3	Coal
916	15.146	0.1729	175177	Coal
917	15.145	0.1696	178692.2	Coal
918	15.511	0.1755	176850.2	Coal
919	14.607	0.1678	173906.9	Coal
920	15.336	0.1762	174091.9	Coal
921	16.101	0.1835	175411.9	Coal
922	15.351	0.1761	174369.7	Coal
923	15.782	0.1796	175721.9	Coal
924	15.025	0.1753	171387.4	Coal
925	15.072	0.1772	170162.3	Coal
926	14.88	0.1741	170949.8	Coal
927	14.233	0.1727	164762.9	Coal
928	14.751	0.173	170499	Coal
929	15.024	0.1758	170974.2	Coal
930	15.382	0.1792	171659.9	Coal
931	15.266	0.1774	172153.9	Coal
932	15.252	0.1808	168450.6	Coal
933	14.595	0.173	168669.4	Coal
934	14.947	0.1773	168637.3	Coal
935	14.792	0.1793	164878.5	Coal
936	15.172	0.1808	167766.2	Coal
937	15.24	0.1789	170375.8	Coal
938	15.733	0.186	169252.3	Coal
939	14.841	0.178	166713.4	Coal
940	12.629	0.1808	138731.4	Coal
941	5.286	0.1363	77589	Coal
942	6.05	0.1411	85996.4	Coal
943	5.9	0.1481	79702.2	Coal
944	6.723	0.1654	81810.221	Coal
945				Coal
946				Coal

	O	P	Q	R
947				Coal
948				Coal
949				Coal
950				Coal
951				Coal
952				Coal
953				Coal
954				Coal
955				Coal
956				Coal
957				Coal
958				Coal
959				Coal
960				Coal
961				Coal
962				Coal
963				Coal
964				Coal
965				Coal
966				Coal
967				Coal
968				Coal
969				Coal
970				Coal
971				Coal
972				Coal
973				Coal
974				Coal
975				Coal
976				Coal
977				Coal
978				Coal
979				Coal
980				Coal
981				Coal
982	6.117	0.4226	29083.64	Coal
983	7.351	0.1765	83329	Coal
984	6.594	0.1444	93375.4	Coal
985	6.328	0.1483	85846.3	Coal
986	6.951	0.1655	83969.6	Coal
987	6.809	0.1376	99509.9	Coal
988	7.08	0.1413	100458.6	Coal
989	5.959	0.1355	88285.1	Coal

	O	P	Q	R
990	5.954	0.1401	85007.8	Coal
991	5.888	0.141	83543.9	Coal
992	6.118	0.1373	89645.7	Coal
993	6.316	0.1254	100775.4	Coal
994	5.99	0.1215	98572.7	Coal
995	6.119	0.1239	98789.1	Coal
996	6.138	0.1312	93587.8	Coal
997	7.285	0.1593	91737.2	Coal
998	6.729	0.1478	91986.5	Coal
999	6.977	0.1472	95411.7	Coal
1000	7.493	0.1541	97393	Coal
1001	6.767	0.1396	96832.6	Coal
1002	5.772	0.1522	82672.636	Coal
1003				Coal
1004				Coal
1005				Coal
1006				Coal
1007				Coal
1008				Coal
1009	4.068	0.438	18575.05	Coal
1010	10.609	0.2321	102552.5	Coal
1011	11.031	0.1544	133078.9	Coal
1012	8.431	0.1446	114569	Coal
1013	12.926	0.172	148901.1	Coal
1014	14.17	0.1714	162934.4	Coal
1015	11.577	0.1495	149126.9	Coal
1016	15.304	0.1762	173721.8	Coal
1017	15.642	0.1799	173906	Coal
1018	15.498	0.1785	173704	Coal
1019	16.091	0.1843	174628.1	Coal
1020	15.883	0.1822	174319.7	Coal
1021	15.295	0.1784	171503.9	Coal
1022	16.048	0.184	174404.2	Coal
1023	15.743	0.1811	173884.5	Coal
1024	15.775	0.1838	171679.5	Coal
1025	15.405	0.1813	169870.9	Coal
1026	15.956	0.1846	172881.3	Coal
1027	14.967	0.1758	170042.6	Coal
1028	14.904	0.1806	165009	Coal
1029	14.639	0.175	167322.7	Coal
1030	13.936	0.1723	161803.3	Coal
1031	14.559	0.1741	167273.2	Coal
1032	14.033	0.1697	165320.8	Coal

	O	P	Q	R
1033	14.763	0.1753	168448.7	Coal
1034	14.865	0.1763	168594.2	Coal
1035	14.78	0.1764	167594.3	Coal
1036	14.534	0.1727	168306.9	Coal
1037	14.815	0.1758	168504.3	Coal
1038	14.257	0.1696	168071.6	Coal
1039	14.638	0.1733	168960.9	Coal
1040	14.724	0.1738	169480.3	Coal
1041	13.819	0.1698	162573.7	Coal
1042	15.146	0.1767	171479.5	Coal
1043	15.064	0.1764	170838.6	Coal
1044	14.623	0.1713	170734.2	Coal
1045	14.889	0.1738	171369.6	Coal
1046	14.184	0.1671	169615.9	Coal
1047	13.695	0.1618	169308.6	Coal
1048	14.513	0.172	168725.5	Coal
1049	14.551	0.1713	169903.2	Coal
1050	14.652	0.1728	169690.7	Coal
1051	11.425	0.1599	140745.1	Coal
1052	13.848	0.1735	159278.5	Coal
1053	13.058	0.1613	161814	Coal
1054	12.568	0.1644	152181	Coal
1055	11.833	0.1578	148643	Coal
1056	13.436	0.169	157605.3	Coal
1057	14.89	0.1754	169780.9	Coal
1058	15.099	0.1787	169052.5	Coal
1059	14.859	0.1756	169274.2	Coal
1060	14.796	0.175	169103.8	Coal
1061	14.809	0.1747	169511.3	Coal
1062	14.405	0.1743	164876.9	Coal
1063	12.574	0.1646	152215.8	Coal
1064	14.309	0.1696	168780.1	Coal
1065	11.699	0.1586	146561.8	Coal
1066	8.379	0.1383	117695.2	Coal
1067	5.229	0.1143	89578	Coal
1068	4.061	0.102	79504.9	Coal
1069	11.55	0.16	142072.6	Coal
1070	14.453	0.1713	168688.1	Coal
1071	13.728	0.1661	165165.5	Coal
1072	14.487	0.1722	168303	Coal
1073	12.746	0.1562	161794.8	Coal
1074	13.083	0.1566	167001	Coal
1075	13.119	0.1605	163023.2	Coal

	O	P	Q	R
1076	12.895	0.1584	161844.5	Coal
1077	14.638	0.1707	171547.2	Coal
1078	14.084	0.1654	170269.6	Coal
1079	13.211	0.1553	170135.3	Coal
1080	13.338	0.156	170949.5	Coal
1081	13.141	0.157	167292.5	Coal
1082	14.016	0.1665	168408.7	Coal
1083	13.795	0.1639	168296.3	Coal
1084	14.737	0.1739	169365.9	Coal
1085	6.367	0.1888	76625.86	Coal
1086				Coal
1087				Coal
1088	2.627	0.438	11995.2	Coal
1089	8.951	0.1749	116544.7	Coal
1090	14.523	0.1689	171999.2	Coal
1091	13.766	0.1656	166221.4	Coal
1092	13.562	0.1688	160443.3	Coal
1093	13.915	0.1708	162675	Coal
1094	16.076	0.1867	172216.2	Coal
1095	15.128	0.1801	167733.6	Coal
1096	14.942	0.1773	168261.9	Coal
1097	15.442	0.18	171556.5	Coal
1098	15.212	0.1762	172714.9	Coal
1099	15.671	0.1823	171629.2	Coal
1100	14.743	0.1702	173252.6	Coal
1101	15.022	0.1732	173456.2	Coal
1102	14.662	0.169	173544.3	Coal
1103	15.121	0.175	172871.6	Coal
1104	14.674	0.169	173699.9	Coal
1105	14.844	0.1714	173121.8	Coal
1106	14.617	0.1682	173778	Coal
1107	14.499	0.1674	173239.8	Coal
1108	14.456	0.1671	173043.6	Coal
1109	14.964	0.1786	167578	Coal
1110	15.245	0.1753	173941.3	Coal
1111	15.428	0.1768	174489.3	Coal
1112	15.467	0.1778	174018.3	Coal
1113	15.693	0.1798	174609.8	Coal
1114	15.246	0.1748	174405.9	Coal
1115	15.046	0.1737	173164.1	Coal
1116	14.328	0.172	166777.3	Coal
1117	11.456	0.1611	141623.1	Coal
1118	14.469	0.1728	166745.4	Coal

	O	P	Q	R
1119	14.437	0.1654	174567.6	Coal
1120	14.66	0.1675	175022.4	Coal
1121	15.676	0.18	174178.9	Coal
1122	16.496	0.1891	174456.9	Coal
1123	16.066	0.1834	175232.8	Coal
1124	14.6	0.1735	164920.7	Coal
1125	16.249	0.1858	174965.7	Coal
1126	15.448	0.1771	174430.2	Coal
1127	15.086	0.175	172365.7	Coal
1128	15.075	0.1763	171052.7	Coal
1129	14.408	0.1761	163510.2	Coal
1130	12.597	0.1643	152667.1	Coal
1131	14.301	0.1696	168355.2	Coal
1132	13.278	0.1712	153876.2	Coal
1133	15.148	0.1785	169689.1	Coal
1134	15.458	0.1763	175374.9	Coal
1135	13.401	0.1679	158881.6	Coal
1136	5.766	0.1487	83491.81	Coal
1137				Coal
1138				Coal
1139				Coal
1140	10.489	0.2621	103317.573	Coal
1141	14.576	0.1676	173868.8	Coal
1142	14.602	0.1709	170982.6	Coal
1143	14.104	0.163	173067.2	Coal
1144	14.085	0.172	163612.2	Coal
1145	15.452	0.1775	174125.1	Coal
1146	12.83	0.1671	152786.8	Coal
1147	10.478	0.1564	134148.8	Coal
1148	2.082	0.1947	23965.48	Coal
1149				Coal
1150				Coal
1151				Coal
1152				Coal
1153				Coal
1154				Coal
1155	0.452	0.438	2065.124	Coal
1156	11.187	0.3425	78800.2	Coal
1157	14.058	0.1682	167172.6	Coal
1158	14.763	0.1746	169109.5	Coal
1159	14.295	0.1672	171020.2	Coal
1160	15.973	0.1908	167467.9	Coal
1161	14.307	0.172	166459	Coal

	O	P	Q	R
1162	14.656	0.1775	165147.4	Coal
1163	14.659	0.1748	167770	Coal
1164	10.054	0.1662	119431.7	Coal
1165	14.334	0.1769	162113.3	Coal
1166	14.435	0.1712	168679.6	Coal
1167	15.06	0.1774	169818.7	Coal
1168	14.828	0.1754	169094.8	Coal
1169	14.557	0.172	169292.9	Coal
1170	14.793	0.1759	168169.4	Coal
1171	15.426	0.1822	169335.1	Coal
1172	15.738	0.1853	169910.6	Coal
1173	14.744	0.1736	169863.2	Coal
1174	14.558	0.174	167247.1	Coal
1175	14.553	0.1712	170027.8	Coal
1176	15.256	0.1798	169706.3	Coal
1177	14.491	0.1733	166805.3	Coal
1178	13.003	0.1671	154731.2	Coal
1179	14.784	0.1753	168648.1	Coal
1180	12.421	0.1645	148624.8	Coal
1181	10.05	0.1527	130973.8	Coal
1182	6.069	0.1645	74884.9	Coal
1183				Coal
1184				Coal
1185				Coal
1186				Coal
1187				Coal
1188				Coal
1189				Coal
1190				Coal
1191				Coal
1192				Coal
1193				Coal
1194				Coal
1195				Coal
1196	0.485	0.464	2088.56	Coal
1197	11.857	0.3713	69665.703	Coal
1198	13.022	0.1623	160562.6	Coal
1199	13.93	0.1683	165512.4	Coal
1200	15.256	0.176	173420.1	Coal
1201	15.382	0.1786	172247.1	Coal
1202	15.257	0.1762	173232.6	Coal
1203	14.723	0.1728	170630.9	Coal
1204	14.456	0.1689	171249.5	Coal

	O	P	Q	R
1205	14.964	0.1739	172128.3	Coal
1206	14.916	0.1707	174764.9	Coal
1207	14.567	0.1707	170765.1	Coal
1208	14.6	0.1665	175472.7	Coal
1209	14.019	0.1573	178090.8	Coal
1210	14.043	0.155	181170	Coal
1211	14.633	0.1616	180995.9	Coal
1212	15.451	0.1703	181425.8	Coal
1213	14.661	0.1636	179138.3	Coal
1214	12.191	0.1505	159739	Coal
1215	10.915	0.1462	143039.1	Coal
1216	12.431	0.157	155425.9	Coal
1217	13.689	0.1638	166678.8	Coal
1218	12.811	0.1583	159525.1	Coal
1219	14.495	0.1699	170668	Coal
1220	11.658	0.155	148832.9	Coal
1221	14.47	0.1687	171535.5	Coal
1222	14.374	0.1667	172494.4	Coal
1223	14.515	0.1678	173055	Coal
1224	14.584	0.1689	172719	Coal
1225	13.798	0.1649	167238.3	Coal
1226	14.441	0.1684	171473.2	Coal
1227	15.012	0.1732	173376	Coal
1228	14.875	0.1712	173773	Coal
1229	13.988	0.1712	162200.2	Coal
1230	15.284	0.1741	175539.5	Coal
1231	14.749	0.1691	174407.4	Coal
1232	14.475	0.1658	174667.4	Coal
1233	7.354	0.1604	90909.936	Coal
1234				Coal
1235				Coal
1236	9.059	0.2834	65658.177	Coal
1237	13.888	0.1601	173295.8	Coal
1238	14.576	0.1697	171706.2	Coal
1239	13.573	0.1668	162379.8	Coal
1240	14.732	0.1708	172444.7	Coal
1241	4.253	0.1013	83409.2	Coal
1242	4.962	0.1209	82100.3	Coal
1243	7.031	0.1428	97624.6	Coal
1244	3.154	0.2012	38406.695	Coal
1245				Coal
1246				Coal
1247				Coal

	O	P	Q	R
1248	24.071	0.5256	92012.214	Coal
1249	29.872	0.372	160603.3	Coal
1250	22.773	0.2531	178398.4	Coal
1251	16.074	0.1838	174873.3	Coal
1252	15.345	0.1755	174869	Coal
1253	14.996	0.1719	174500.4	Coal
1254	14.535	0.1672	173892.4	Coal
1255	13.406	0.1674	158819.7	Coal
1256	8.585	0.1523	112660.8	Coal
1257	12.542	0.1621	153723	Coal
1258	7.39	0.149	99369.6	Coal
1259	12.389	0.1592	153107.9	Coal
1260	12.316	0.1572	152207.6	Coal
1261	11.036	0.1545	139696.3	Coal
1262	8.608	0.1508	115047.8	Coal
1263	8.195	0.1563	105606.4	Coal
1264	8.812	0.1571	112046.4	Coal
1265	8.65	0.1726	104843.732	Coal
1266				Coal
1267				Coal
1268				Coal
1269				Coal
1270				Coal
1271				Coal
1272				Coal
1273				Coal
1274				Coal
1275				Coal
1276				Coal
1277				Coal
1278				Coal
1279				Coal
1280				Coal
1281				Coal
1282				Coal
1283				Coal
1284				Coal
1285				Coal
1286				Coal
1287				Coal
1288				Coal
1289				Coal
1290				Coal

	O	P	Q	R
1291				Coal
1292				Coal
1293				Coal
1294				Coal
1295				Coal
1296				Coal
1297				Coal
1298				Coal
1299				Coal
1300				Coal
1301				Coal
1302				Coal
1303				Coal
1304				Coal
1305				Coal
1306				Coal
1307				Coal
1308				Coal
1309				Coal
1310				Coal
1311				Coal
1312				Coal
1313				Coal
1314				Coal
1315				Coal
1316				Coal
1317				Coal
1318				Coal
1319				Coal
1320				Coal
1321				Coal
1322				Coal
1323				Coal
1324				Coal
1325				Coal
1326				Coal
1327				Coal
1328				Coal
1329				Coal
1330				Coal
1331				Coal
1332				Coal
1333				Coal

	O	P	Q	R
1334				Coal
1335				Coal
1336				Coal
1337				Coal
1338				Coal
1339				Coal
1340				Coal
1341				Coal
1342				Coal
1343				Coal
1344				Coal
1345				Coal
1346				Coal
1347				Coal
1348				Coal
1349				Coal
1350				Coal
1351				Coal
1352				Coal
1353				Coal
1354				Coal
1355				Coal
1356				Coal
1357				Coal
1358				Coal
1359				Coal
1360				Coal
1361	5.584	0.564	19801.296	Coal
1362	10.2	0.564	36169.704	Coal
1363	16.665	0.4366	75654.4	Coal
1364				Coal
1365				Coal
1366				Coal
1367				Coal
1368	0.003	0.417	14.03	Coal
1369	4.734	0.2633	41055.2	Coal
1370	2.992	0.1187	49123.6	Coal
1371				Coal
1372	3.732	0.403	18552.705	Coal
1373	2.311	0.1182	37735.4	Coal
1374	2.413	0.1485	32191.3	Coal
1375	2.174	0.1449	29364.9	Coal
1376	2.4	0.1503	31337.7	Coal

	O	P	Q	R
1377	8.823	0.1563	108503.1	Coal
1378	15.008	0.1706	175968.7	Coal
1379	14.318	0.1632	175479.9	Coal
1380	14.062	0.1603	175454.7	Coal
1381	13.73	0.1603	170676	Coal
1382	9.635	0.1436	130918.9	Coal
1383	9.879	0.1515	126488	Coal
1384	10.954	0.1538	138055.8	Coal
1385	15.077	0.1705	176895.3	Coal
1386	14.862	0.1693	175661.3	Coal
1387	13.987	0.167	166119.6	Coal
1388	15.398	0.1732	177802.3	Coal
1389	14.616	0.171	170266.9	Coal
1390	13.001	0.1655	154807.7	Coal
1391	14.464	0.1707	169681.3	Coal
1392	13.435	0.1667	159317.4	Coal
1393	9.2	0.1534	118958.7	Coal
1394	11.256	0.1542	145559.3	Coal
1395	8.908	0.1488	119896.5	Coal
1396	7.307	0.1623	90066.6	Coal
1397	10.146	0.16	126313.9	Coal
1398	9.972	0.1662	118773.7	Coal
1399	13.181	0.1818	144268.2	Coal
1400	13.922	0.1805	154223.5	Coal
1401	14.159	0.1845	153418.5	Coal
1402	11.196	0.1784	125064.6	Coal
1403	12.182	0.1823	133528.3	Coal
1404	13.123	0.1745	149928.2	Coal
1405	11.583	0.1779	129295.5	Coal
1406	13.841	0.1799	153838.9	Coal
1407	13.899	0.1829	151905.5	Coal
1408	14.685	0.1861	157874.4	Coal
1409	13.124	0.1772	146572.1	Coal
1410	8.5	0.1587	105027.2	Coal
1411	9.827	0.1637	117481.4	Coal
1412	6.685	0.1709	78204	Coal
1413	9.708	0.1583	122295.4	Coal
1414	10.508	0.2078	107271.382	Coal
1415	12.857	0.1681	153782.5	Coal
1416	12.922	0.1583	163122.8	Coal
1417	9.494	0.1628	117089.2	Coal
1418	12.734	0.165	149970.6	Coal
1419	10.428	0.1556	130862.9	Coal

	O	P	Q	R
1420	10.906	0.153	139136.1	Coal
1421	11.985	0.1583	150136.4	Coal
1422	5.726	0.122	93862.8	Coal
1423	6.378	0.134	95230	Coal
1424	6.409	0.1328	96331.8	Coal
1425	9.954	0.1495	129018.2	Coal
1426	4.538	0.0964	94131.9	Coal
1427	6.406	0.1171	105659.3	Coal
1428	11.827	0.1593	145166.3	Coal
1429	12.164	0.1638	146788.6	Coal
1430	10.893	0.1526	138632.2	Coal
1431	8.501	0.1491	112514.6	Coal
1432	7.393	0.1412	104044.7	Coal
1433	13.596	0.1684	157051.2	Coal
1434	15.981	0.1763	181306.1	Coal
1435	16.45	0.1785	184326.9	Coal
1436	15.47	0.1725	179329.4	Coal
1437	14.738	0.169	174310.2	Coal
1438	13.226	0.1593	165886.4	Coal
1439	12.579	0.1637	150073.2	Coal
1440	11.75	0.1587	142843.4	Coal
1441	10.285	0.1506	131212.8	Coal
1442	5.44	0.1124	96466.6	Coal
1443	7.543	0.1232	116937.1	Coal
1444	7.691	0.1349	111631.1	Coal
1445	7.367	0.1527	96480.7	Coal
1446	10.787	0.1745	138333.904	Coal
1447				Coal
1448				Coal
1449				Coal
1450				Coal
1451				Coal
1452	1.458	0.368	7926.255	Coal
1453	4.857	0.3629	26815.292	Coal
1454	11.657	0.1524	150840	Coal
1455	13.768	0.1628	166771.1	Coal
1456	13.307	0.1615	161633.1	Coal
1457	13.685	0.164	165035.7	Coal
1458	15.437	0.1712	178884.5	Coal
1459	8.444	0.144	115507.4	Coal
1460	15.351	0.1682	182493.6	Coal
1461	15.473	0.1748	175960.9	Coal
1462	15.117	0.1761	170925.3	Coal

	O	P	Q	R
1463	15.831	0.1759	180158.6	Coal
1464	14.233	0.1668	167357.5	Coal
1465	13.979	0.1624	166149	Coal
1466	15.959	0.1723	185189.4	Coal
1467	16.307	0.1798	181293.9	Coal
1468	15.317	0.1747	175228	Coal
1469	15.912	0.1783	178448.4	Coal
1470	15.721	0.1713	183497.6	Coal
1471	15.424	0.167	184685.7	Coal
1472	15.864	0.1713	185226.8	Coal
1473	14.461	0.1632	177515.4	Coal
1474	14.56	0.1645	176193.9	Coal
1475	14.579	0.173	166953.6	Coal
1476	12.962	0.1633	156329.3	Coal
1477	13.447	0.1612	162257.5	Coal
1478	13.212	0.1632	159408.7	Coal
1479	7.257	0.1426	101869.1	Coal
1480	7.835	0.1477	105561.4	Coal
1481	12.631	0.1654	151820.4	Coal
1482	4.506	0.2015	55831.06	Coal
1483				Coal
1484	1.613	0.602	5358.186	Coal
1485	12.266	0.1835	143762.9	Coal
1486	13.331	0.1651	158766.3	Coal
1487	7.064	0.1401	100745.5	Coal
1488	12.843	0.1605	156871.6	Coal
1489	13.53	0.1685	159040	Coal
1490	15.055	0.1677	179609.8	Coal
1491	11.321	0.1502	147339.9	Coal
1492	7.241	0.127	111887.9	Coal
1493	4.389	0.0952	92216	Coal
1494	4.207	0.0913	92163.7	Coal
1495	5.762	0.1158	98519	Coal
1496	8.748	0.1358	124991	Coal
1497	14.48	0.1645	175965	Coal
1498	14.473	0.1653	174923.8	Coal
1499	11.194	0.1462	148540.4	Coal
1500	7.784	0.1431	108135.7	Coal
1501	7.541	0.1573	95858.1	Coal
1502	7.68	0.1481	103990.6	Coal
1503	8.401	0.1655	102122.8	Coal
1504	8.224	0.1544	106739.6	Coal
1505	9.535	0.1483	125350.2	Coal

	O	P	Q	R
1506	11.605	0.1553	147924.1	Coal
1507	8.317	0.141	116511.5	Coal
1508	6.523	0.1307	99721.7	Coal
1509	9.997	0.1543	126232.4	Coal
1510	14.423	0.1697	169611.6	Coal
1511	11.203	0.1545	144218.4	Coal
1512	14.511	0.1619	179332.4	Coal
1513	15.631	0.1711	182695.1	Coal
1514	14.737	0.1686	172700.6	Coal
1515	13.293	0.152	173109.6	Coal
1516	16.635	0.1815	183216.3	Coal
1517	15.67	0.1716	182627.8	Coal
1518	12.901	0.1504	169491.7	Coal
1519	14.135	0.1595	177166.2	Coal
1520	14.074	0.1624	173395.9	Coal
1521	14.071	0.1592	176904.7	Coal
1522	14.743	0.1635	180324.8	Coal
1523	14.585	0.161	181111.5	Coal
1524	10.138	0.1365	142505.2	Coal
1525	0.287	0.273	3490.75	Coal
1526	0.458	0.602	1522.008	Coal
1527				Coal
1528				Coal
1529	5.237	0.602	17397.397	Coal
1530	9.915	0.243	108377.8	Coal
1531	14.009	0.1612	173507.3	Coal
1532	14.363	0.1606	178867.6	Coal
1533	15.149	0.1684	179945.7	Coal
1534	14.158	0.1576	179863.8	Coal
1535	13.035	0.1523	170608.1	Coal
1536	10.838	0.1544	139334.9	Coal
1537	15.215	0.167	182158.6	Coal
1538	14.057	0.162	173008.5	Coal
1539	7.495	0.1478	101553.7	Coal
1540	12.839	0.1532	166571.6	Coal
1541	13.668	0.1644	165319	Coal
1542	12.589	0.1612	156216.5	Coal
1543	12.554	0.156	155834.5	Coal
1544	10.907	0.1444	146824.9	Coal
1545	6.686	0.1252	106157	Coal
1546	6.622	0.1398	94761.4	Coal
1547	6.621	0.1381	95963.9	Coal
1548	6.471	0.1347	96104.4	Coal

	O	P	Q	R
1549	6.372	0.1335	95467	Coal
1550	6.52	0.1377	94699.7	Coal
1551	6.482	0.1374	94360.3	Coal
1552	12.622	0.1778	141425	Coal
1553	8.147	0.1779	90578.9	Coal
1554	12.264	0.1923	127077.8	Coal
1555	13.528	0.2052	131792.3	Coal
1556	13.403	0.2097	127449.5	Coal
1557	10.896	0.1878	114253.6	Coal
1558	13.666	0.2013	135808	Coal
1559	13.331	0.1956	136245.9	Coal
1560	11.875	0.1853	127863.6	Coal
1561	11.41	0.1852	122961.8	Coal
1562	0.366	0.3095	2710.94	Coal
1563	4.734	0.3641	31626.186	Coal
1564	10.407	0.1794	114924.9	Coal
1565	12.905	0.1908	135192.5	Coal
1566	13.637	0.1971	138322.7	Coal
1567	13.342	0.194	137546.1	Coal
1568	12.503	0.1843	135658.7	Coal
1569	12.809	0.1865	137349.6	Coal
1570	12.928	0.1882	137355.3	Coal
1571	12.743	0.1838	138667.1	Coal
1572	13.089	0.1894	138233	Coal
1573	13.028	0.1883	138381	Coal
1574	12.443	0.1799	138322.7	Coal
1575	12.425	0.1832	135658.4	Coal
1576	12.679	0.1823	139075.1	Coal
1577	12.508	0.1813	138004.3	Coal
1578	12.451	0.18	138322.4	Coal
1579	11.917	0.1733	137541.5	Coal
1580	12.067	0.1752	137773.4	Coal
1581	12.491	0.1801	138698.2	Coal
1582	12.536	0.18	139256.8	Coal
1583	11.736	0.1722	136443.1	Coal
1584	11.824	0.1804	131042	Coal
1585	12.215	0.181	134938.7	Coal
1586	12.283	0.1802	136357.6	Coal
1587	12.39	0.1805	137244.3	Coal
1588	12.418	0.1805	137450.8	Coal
1589	12.354	0.179	138042.5	Coal
1590	12.153	0.1797	135283.3	Coal
1591	11.893	0.1803	131693.5	Coal

	O	P	Q	R
1592	11.657	0.1793	129811.4	Coal
1593	12.363	0.1853	133593.3	Coal
1594	12.883	0.1835	140447	Coal
1595	12.639	0.1823	138699.7	Coal
1596	12.695	0.1831	138675.9	Coal
1597	12.353	0.1793	137819.5	Coal
1598	11.751	0.1797	130723.9	Coal
1599	12.139	0.1797	135095.3	Coal
1600	12.606	0.1799	140140.4	Coal
1601	12.678	0.1773	142966	Coal
1602	12.798	0.1821	140569.5	Coal
1603	11.575	0.1804	128241.8	Coal
1604	12.631	0.1874	134799.3	Coal
1605	7.896	0.1752	90010.2	Coal
1606	7.226	0.1658	85797	Coal
1607	8.538	0.1936	92506.8	Coal
1608	0	0.017	5.655	Coal
1609				Coal
1610				Coal
1611				Coal
1612				Coal
1613				Coal
1614	0.096	0.017	11314.645	Coal
1615	6.225	0.141	79128.1	Coal
1616	12.444	0.1812	137483.7	Coal
1617	12.75	0.1811	140734.9	Coal
1618	11.446	0.179	127910.9	Coal
1619	10.489	0.1771	117590.7	Coal
1620	7.385	0.1799	82245	Coal
1621	11.542	0.1814	126637.3	Coal
1622	13.413	0.1866	143734.3	Coal
1623	13.51	0.1894	142676	Coal
1624	11.658	0.1803	127993.6	Coal
1625	13.349	0.1861	143450	Coal
1626	9.282	0.1674	105942.9	Coal
1627	8.15	0.1696	94525.5	Coal
1628	12.821	0.1916	133736.1	Coal
1629	12.729	0.1913	132616.2	Coal
1630	13.521	0.192	140748.1	Coal
1631	9.174	0.1803	101498.5	Coal
1632	7.456	0.1658	89308.4	Coal
1633	5.968	0.1644	72633	Coal
1634	6.183	0.1697	72873.2	Coal

	O	P	Q	R
1635	6.579	0.1743	75502	Coal
1636	8.267	0.1569	100513.8	Coal
1637	4.915	0.1691	58682.01	Coal
1638				Coal
1639				Coal
1640				Coal
1641				Coal
1642				Coal
1643				Coal
1644				Coal
1645				Coal
1646				Coal
1647				Coal
1648				Coal
1649				Coal
1650				Coal
1651				Coal
1652				Coal
1653				Coal
1654				Coal
1655				Coal
1656				Coal
1657				Coal
1658				Coal
1659				Coal
1660				Coal
1661				Coal
1662				Coal
1663				Coal
1664				Coal
1665				Coal
1666				Coal
1667				Coal
1668				Coal
1669				Coal
1670				Coal
1671				Coal
1672				Coal
1673				Coal
1674				Coal
1675				Coal
1676				Coal
1677				Coal

	O	P	Q	R
1678				Coal
1679				Coal
1680				Coal
1681				Coal
1682				Coal
1683				Coal
1684				Coal
1685				Coal
1686				Coal
1687				Coal
1688				Coal
1689				Coal
1690				Coal
1691				Coal
1692				Coal
1693				Coal
1694				Coal
1695				Coal
1696				Coal
1697				Coal
1698				Coal
1699				Coal
1700				Coal
1701				Coal
1702				Coal
1703				Coal
1704				Coal
1705				Coal
1706				Coal
1707				Coal
1708	4.469	0.438	20406.19	Coal
1709	7.706	0.1945	81247.9	Coal
1710	8.327	0.1877	87343	Coal
1711	8.28	0.1989	81927.844	Coal
1712				Coal
1713				Coal
1714	4.428	0.2664	40497.747	Coal
1715	4.946	0.1428	68727.7	Coal
1716	5.655	0.1662	68114.9	Coal
1717	5.67	0.1685	67278.1	Coal
1718	7.506	0.1653	86851.9	Coal
1719	8.968	0.1719	102292.3	Coal
1720	8.091	0.1665	93384.8	Coal

	O	P	Q	R
1721	10.411	0.1809	112317.7	Coal
1722	12.107	0.1897	127519.2	Coal
1723	5.933	0.181	65523.2	Coal
1724	5.637	0.1734	65015.8	Coal
1725	5.994	0.175	68287.1	Coal
1726	11.632	0.1873	124190.8	Coal
1727	12.817	0.1901	134831.5	Coal
1728	10.148	0.1971	102572.4	Coal
1729	10.967	0.1903	114838	Coal
1730	10.541	0.1933	108685.5	Coal
1731	10.099	0.1944	104709.3	Coal
1732	11.128	0.185	119937.2	Coal
1733	12.335	0.1863	132400.3	Coal
1734	11.476	0.1831	125097.3	Coal
1735	5.634	0.163	69201.2	Coal
1736	8.965	0.1672	104952.6	Coal
1737	8.578	0.1829	93431.5	Coal
1738	9.529	0.179	105493.3	Coal
1739	10.64	0.1818	116790.8	Coal
1740	12.342	0.1854	133111.1	Coal
1741	12.969	0.1943	133490.7	Coal
1742	12.349	0.1887	130803.2	Coal
1743	11.828	0.1847	128085.2	Coal
1744	11.705	0.1826	128196.9	Coal
1745	11.881	0.1868	127346.2	Coal
1746	11.702	0.1808	129462.4	Coal
1747	10.659	0.184	115739.8	Coal
1748	12.02	0.1838	130792	Coal
1749	12.123	0.186	130370.2	Coal
1750	11.482	0.1775	129290.2	Coal
1751	11.3	0.1829	123072.6	Coal
1752	8.599	0.187	91642.5	Coal
1753	9.727	0.1793	108278.4	Coal
1754	11.975	0.1859	128759.6	Coal
1755	11.995	0.1834	130811.7	Coal
1756	12.097	0.1856	130403.8	Coal
1757	10.315	0.1891	112714.845	Coal
1758				Coal
1759				Coal
1760				Coal
1761	0.194	0.438	887.315	Coal
1762	7.499	0.3179	58581.1	Coal
1763	12.096	0.185	130735.7	Coal

	O	P	Q	R
1764	12.77	0.185	138053.8	Coal
1765	11.38	0.1849	122688	Coal
1766	9.2	0.184	99808.1	Coal
1767	6.45	0.1754	73479	Coal
1768	8.524	0.1697	101053.9	Coal
1769	10.516	0.1736	119384.4	Coal
1770	9.444	0.172	109265.5	Coal
1771	8.047	0.1685	95769.4	Coal
1772	10.38	0.1702	121750.7	Coal
1773	10.559	0.1678	125411.2	Coal
1774	5.217	0.2412	62648.872	Coal
1775				Coal
1776	2.456	0.3618	16803.254	Coal
1777				Coal
1778				Coal
1779				Coal
1780	0.562	0.438	2565.024	Coal
1781	0.961	0.438	4386.08	Coal
1782	9.656	0.2885	91626.9	Coal
1783	13.631	0.1777	153124.4	Coal
1784	13.954	0.1795	155355.9	Coal
1785	14.702	0.1853	158655	Coal
1786	13.544	0.1742	155485.3	Coal
1787	14.022	0.1786	156981.1	Coal
1788	13.603	0.1772	153456.9	Coal
1789	14.202	0.18	157795.9	Coal
1790	13.166	0.244	125179.655	Coal
1791	13.565	0.1717	158044.2	Coal
1792	13.656	0.1735	157331.2	Coal
1793	13.708	0.1792	152766.4	Coal
1794	11.844	0.1745	135032.9	Coal
1795	8.003	0.1624	98218	Coal
1796	11.182	0.1699	130233.4	Coal
1797	13.825	0.1749	158100.7	Coal
1798	13.951	0.1773	157367.4	Coal
1799	13.86	0.1765	157053.1	Coal
1800	14.325	0.181	158348.9	Coal
1801	13.735	0.1755	156449.2	Coal
1802	11.585	0.1708	133927.6	Coal
1803	2.611	0.2212	28688.656	Coal
1804				Coal
1805				Coal
1806				Coal

	O	P	Q	R
1807	8.344	0.4209	39767.525	Coal
1808	8.906	0.1641	107442	Coal
1809	6.634	0.1588	83574.2	Coal
1810	13.342	0.182	146255.6	Coal
1811	14.195	0.1802	157417.8	Coal
1812	13.356	0.1798	147172.4	Coal
1813	12.502	0.1731	142746.1	Coal
1814	14.546	0.1754	165812	Coal
1815	12.512	0.1738	143819.5	Coal
1816	7.802	0.1587	98117.7	Coal
1817	14.511	0.1763	164365.8	Coal
1818	14.897	0.1759	169418.5	Coal
1819	15.004	0.177	169524.2	Coal
1820	13.424	0.1751	152476.6	Coal
1821	13.578	0.1755	153008.7	Coal
1822	14.747	0.1765	167203	Coal
1823	14.097	0.175	160945.3	Coal
1824	12.435	0.1695	146109.8	Coal
1825	12.427	0.1684	147863.2	Coal
1826	12.431	0.1703	146281.6	Coal
1827	13.89	0.1717	161700.1	Coal
1828	12.777	0.1668	152934.2	Coal
1829	12.781	0.169	151005.9	Coal
1830	11.738	0.1646	141194.2	Coal
1831	13.817	0.1677	164839	Coal
1832	14.241	0.1712	166401.4	Coal
1833	14.508	0.174	166715.7	Coal
1834	14.497	0.175	165707.4	Coal
1835	13.791	0.1708	161453.5	Coal
1836	7.464	0.1635	91100.6	Coal
1837	10.262	0.1673	121151.7	Coal
1838	14.512	0.1776	163556.1	Coal
1839	14.669	0.1785	164279.1	Coal
1840	14.842	0.1789	165930.9	Coal
1841	13.634	0.1698	160111.1	Coal
1842	10.909	0.1714	126620.2	Coal
1843	14.669	0.1793	163580.5	Coal
1844	8.333	0.167	99403	Coal
1845	11.494	0.1701	133479.5	Coal
1846	14.075	0.1737	162139.8	Coal
1847	14.31	0.1728	165643.1	Coal
1848	14.353	0.1712	167651.8	Coal
1849	15.496	0.195	158015.3	Coal

	O	P	Q	R
1850	12.432	0.1705	144136.3	Coal
1851	11.701	0.1718	134345.5	Coal
1852	13.373	0.1738	153412.8	Coal
1853	14.806	0.1803	164188.5	Coal
1854	13.626	0.1814	150641.8	Coal
1855	16.931	0.169	200786.3	Coal
1856	18.914	0.1743	217031.2	Coal
1857	12.628	0.1405	178435.8	Coal
1858	13.259	0.1448	182041.1	Coal
1859	17.401	0.1623	212682.6	Coal
1860	17.27	0.1724	200960.6	Coal
1861	15.158	0.1777	169602.4	Coal
1862	14.446	0.1787	159883.8	Coal
1863	11.337	0.1663	134544	Coal
1864	15.184	0.1713	177286.9	Coal
1865	13.471	0.1716	157122.4	Coal
1866	15.368	0.1762	174460	Coal
1867	15.714	0.1766	177977.8	Coal
1868	15.499	0.1732	179008.7	Coal
1869	13.628	0.1657	163163.1	Coal
1870	14.256	0.1753	162070.9	Coal
1871	15.965	0.1823	175151.8	Coal
1872	15.55	0.1761	176590.9	Coal
1873	15.09	0.1747	172847.6	Coal
1874	15.36	0.1825	167846	Coal
1875	8.636	0.1718	103710.3	Coal
1876	15.297	0.1763	173538.4	Coal
1877	15.731	0.1799	174867.5	Coal
1878	15.633	0.178	175571.7	Coal
1879	14.949	0.1756	170133.1	Coal
1880	15.584	0.1822	170852.2	Coal
1881	16.147	0.1854	174160.1	Coal
1882	14.967	0.1737	172342.6	Coal
1883	15.421	0.1762	175070.7	Coal
1884	7.893	0.164	96270.1	Coal
1885	3.543	0.2055	39685.023	Coal
1886				Coal
1887				Coal
1888				Coal
1889				Coal
1890				Coal
1891				Coal
1892				Coal

	O	P	Q	R
1893	0.873	0.438	3984.02	Coal
1894	6.966	0.3994	39479.646	Coal
1895	10.773	0.1653	127935.5	Coal
1896	8.028	0.1617	99305	Coal
1897	11.246	0.1705	131213	Coal
1898	8.129	0.1638	99396.7	Coal
1899	9.501	0.1757	108164.4	Coal
1900	8.472	0.1702	99515.4	Coal
1901	8.512	0.171	99454.6	Coal
1902	7.789	0.165	94465.2	Coal
1903	8.118	0.165	99179.2	Coal
1904	7.09	0.1458	101351.7	Coal
1905	0.002	0.099	39.534	Coal
1906				Coal
1907				Coal
1908				Coal
1909				Coal
1910				Coal
1911				Coal
1912				Coal
1913				Coal
1914				Coal
1915				Coal
1916				Coal
1917				Coal

	S	T	U
1	Secondary Fuel Type	Unit Type	SO2 Controls
2		Tangentially-fired	Wet Limestone
3		Tangentially-fired	Wet Limestone
4		Tangentially-fired	Wet Limestone
5		Tangentially-fired	Wet Limestone
6		Tangentially-fired	Wet Limestone
7		Tangentially-fired	Wet Limestone
8		Tangentially-fired	Wet Limestone
9		Tangentially-fired	Wet Limestone
10		Tangentially-fired	Wet Limestone
11		Tangentially-fired	Wet Limestone
12		Tangentially-fired	Wet Limestone
13		Tangentially-fired	Wet Limestone
14		Tangentially-fired	Wet Limestone
15		Tangentially-fired	Wet Limestone
16		Tangentially-fired	Wet Limestone
17		Tangentially-fired	Wet Limestone
18		Tangentially-fired	Wet Limestone
19		Tangentially-fired	Wet Limestone
20		Tangentially-fired	Wet Limestone
21		Tangentially-fired	Wet Limestone
22		Tangentially-fired	Wet Limestone
23		Tangentially-fired	Wet Limestone
24		Tangentially-fired	Wet Limestone
25		Tangentially-fired	Wet Limestone
26		Tangentially-fired	Wet Limestone
27		Tangentially-fired	Wet Limestone
28		Tangentially-fired	Wet Limestone
29		Tangentially-fired	Wet Limestone
30		Tangentially-fired	Wet Limestone
31		Tangentially-fired	Wet Limestone
32		Tangentially-fired	Wet Limestone
33		Tangentially-fired	Wet Limestone
34		Tangentially-fired	Wet Limestone
35		Tangentially-fired	Wet Limestone
36		Tangentially-fired	Wet Limestone
37		Tangentially-fired	Wet Limestone
38		Tangentially-fired	Wet Limestone
39		Tangentially-fired	Wet Limestone
40		Tangentially-fired	Wet Limestone
41		Tangentially-fired	Wet Limestone
42		Tangentially-fired	Wet Limestone
43		Tangentially-fired	Wet Limestone

	S	T	U
44		Tangentially-fired	Wet Limestone
45		Tangentially-fired	Wet Limestone
46		Tangentially-fired	Wet Limestone
47		Tangentially-fired	Wet Limestone
48		Tangentially-fired	Wet Limestone
49		Tangentially-fired	Wet Limestone
50		Tangentially-fired	Wet Limestone
51		Tangentially-fired	Wet Limestone
52		Tangentially-fired	Wet Limestone
53		Tangentially-fired	Wet Limestone
54		Tangentially-fired	Wet Limestone
55		Tangentially-fired	Wet Limestone
56		Tangentially-fired	Wet Limestone
57		Tangentially-fired	Wet Limestone
58		Tangentially-fired	Wet Limestone
59		Tangentially-fired	Wet Limestone
60		Tangentially-fired	Wet Limestone
61		Tangentially-fired	Wet Limestone
62		Tangentially-fired	Wet Limestone
63		Tangentially-fired	Wet Limestone
64		Tangentially-fired	Wet Limestone
65		Tangentially-fired	Wet Limestone
66		Tangentially-fired	Wet Limestone
67		Tangentially-fired	Wet Limestone
68		Tangentially-fired	Wet Limestone
69		Tangentially-fired	Wet Limestone
70		Tangentially-fired	Wet Limestone
71		Tangentially-fired	Wet Limestone
72		Tangentially-fired	Wet Limestone
73		Tangentially-fired	Wet Limestone
74		Tangentially-fired	Wet Limestone
75		Tangentially-fired	Wet Limestone
76		Tangentially-fired	Wet Limestone
77		Tangentially-fired	Wet Limestone
78		Tangentially-fired	Wet Limestone
79		Tangentially-fired	Wet Limestone
80		Tangentially-fired	Wet Limestone
81		Tangentially-fired	Wet Limestone
82		Tangentially-fired	Wet Limestone
83		Tangentially-fired	Wet Limestone
84		Tangentially-fired	Wet Limestone
85		Tangentially-fired	Wet Limestone
86		Tangentially-fired	Wet Limestone

	S	T	U
87		Tangentially-fired	Wet Limestone
88		Tangentially-fired	Wet Limestone
89		Tangentially-fired	Wet Limestone
90		Tangentially-fired	Wet Limestone
91		Tangentially-fired	Wet Limestone
92		Tangentially-fired	Wet Limestone
93		Tangentially-fired	Wet Limestone
94		Tangentially-fired	Wet Limestone
95		Tangentially-fired	Wet Limestone
96		Tangentially-fired	Wet Limestone
97		Tangentially-fired	Wet Limestone
98		Tangentially-fired	Wet Limestone
99		Tangentially-fired	Wet Limestone
100		Tangentially-fired	Wet Limestone
101		Tangentially-fired	Wet Limestone
102		Tangentially-fired	Wet Limestone
103		Tangentially-fired	Wet Limestone
104		Tangentially-fired	Wet Limestone
105		Tangentially-fired	Wet Limestone
106		Tangentially-fired	Wet Limestone
107		Tangentially-fired	Wet Limestone
108		Tangentially-fired	Wet Limestone
109		Tangentially-fired	Wet Limestone
110		Tangentially-fired	Wet Limestone
111		Tangentially-fired	Wet Limestone
112		Tangentially-fired	Wet Limestone
113		Tangentially-fired	Wet Limestone
114		Tangentially-fired	Wet Limestone
115		Tangentially-fired	Wet Limestone
116		Tangentially-fired	Wet Limestone
117		Tangentially-fired	Wet Limestone
118		Tangentially-fired	Wet Limestone
119		Tangentially-fired	Wet Limestone
120		Tangentially-fired	Wet Limestone
121		Tangentially-fired	Wet Limestone
122		Tangentially-fired	Wet Limestone
123		Tangentially-fired	Wet Limestone
124		Tangentially-fired	Wet Limestone
125		Tangentially-fired	Wet Limestone
126		Tangentially-fired	Wet Limestone
127		Tangentially-fired	Wet Limestone
128		Tangentially-fired	Wet Limestone
129		Tangentially-fired	Wet Limestone

	S	T	U
130		Tangentially-fired	Wet Limestone
131		Tangentially-fired	Wet Limestone
132		Tangentially-fired	Wet Limestone
133		Tangentially-fired	Wet Limestone
134		Tangentially-fired	Wet Limestone
135		Tangentially-fired	Wet Limestone
136		Tangentially-fired	Wet Limestone
137		Tangentially-fired	Wet Limestone
138		Tangentially-fired	Wet Limestone
139		Tangentially-fired	Wet Limestone
140		Tangentially-fired	Wet Limestone
141		Tangentially-fired	Wet Limestone
142		Tangentially-fired	Wet Limestone
143		Tangentially-fired	Wet Limestone
144		Tangentially-fired	Wet Limestone
145		Tangentially-fired	Wet Limestone
146		Tangentially-fired	Wet Limestone
147		Tangentially-fired	Wet Limestone
148		Tangentially-fired	Wet Limestone
149		Tangentially-fired	Wet Limestone
150		Tangentially-fired	Wet Limestone
151		Tangentially-fired	Wet Limestone
152		Tangentially-fired	Wet Limestone
153		Tangentially-fired	Wet Limestone
154		Tangentially-fired	Wet Limestone
155		Tangentially-fired	Wet Limestone
156		Tangentially-fired	Wet Limestone
157		Tangentially-fired	Wet Limestone
158		Tangentially-fired	Wet Limestone
159		Tangentially-fired	Wet Limestone
160		Tangentially-fired	Wet Limestone
161		Tangentially-fired	Wet Limestone
162		Tangentially-fired	Wet Limestone
163		Tangentially-fired	Wet Limestone
164		Tangentially-fired	Wet Limestone
165		Tangentially-fired	Wet Limestone
166		Tangentially-fired	Wet Limestone
167		Tangentially-fired	Wet Limestone
168		Tangentially-fired	Wet Limestone
169		Tangentially-fired	Wet Limestone
170		Tangentially-fired	Wet Limestone
171		Tangentially-fired	Wet Limestone
172		Tangentially-fired	Wet Limestone

	S	T	U
173		Tangentially-fired	Wet Limestone
174		Tangentially-fired	Wet Limestone
175		Tangentially-fired	Wet Limestone
176		Tangentially-fired	Wet Limestone
177		Tangentially-fired	Wet Limestone
178		Tangentially-fired	Wet Limestone
179		Tangentially-fired	Wet Limestone
180		Tangentially-fired	Wet Limestone
181		Tangentially-fired	Wet Limestone
182		Tangentially-fired	Wet Limestone
183		Tangentially-fired	Wet Limestone
184		Tangentially-fired	Wet Limestone
185		Tangentially-fired	Wet Limestone
186		Tangentially-fired	Wet Limestone
187		Tangentially-fired	Wet Limestone
188		Tangentially-fired	Wet Limestone
189		Tangentially-fired	Wet Limestone
190		Tangentially-fired	Wet Limestone
191		Tangentially-fired	Wet Limestone
192		Tangentially-fired	Wet Limestone
193		Tangentially-fired	Wet Limestone
194		Tangentially-fired	Wet Limestone
195		Tangentially-fired	Wet Limestone
196		Tangentially-fired	Wet Limestone
197		Tangentially-fired	Wet Limestone
198		Tangentially-fired	Wet Limestone
199		Tangentially-fired	Wet Limestone
200		Tangentially-fired	Wet Limestone
201		Tangentially-fired	Wet Limestone
202		Tangentially-fired	Wet Limestone
203		Tangentially-fired	Wet Limestone
204		Tangentially-fired	Wet Limestone
205		Tangentially-fired	Wet Limestone
206		Tangentially-fired	Wet Limestone
207		Tangentially-fired	Wet Limestone
208		Tangentially-fired	Wet Limestone
209		Tangentially-fired	Wet Limestone
210		Tangentially-fired	Wet Limestone
211		Tangentially-fired	Wet Limestone
212		Tangentially-fired	Wet Limestone
213		Tangentially-fired	Wet Limestone
214		Tangentially-fired	Wet Limestone
215		Tangentially-fired	Wet Limestone

	S	T	U
216		Tangentially-fired	Wet Limestone
217		Tangentially-fired	Wet Limestone
218		Tangentially-fired	Wet Limestone
219		Tangentially-fired	Wet Limestone
220		Tangentially-fired	Wet Limestone
221		Tangentially-fired	Wet Limestone
222		Tangentially-fired	Wet Limestone
223		Tangentially-fired	Wet Limestone
224		Tangentially-fired	Wet Limestone
225		Tangentially-fired	Wet Limestone
226		Tangentially-fired	Wet Limestone
227		Tangentially-fired	Wet Limestone
228		Tangentially-fired	Wet Limestone
229		Tangentially-fired	Wet Limestone
230		Tangentially-fired	Wet Limestone
231		Tangentially-fired	Wet Limestone
232		Tangentially-fired	Wet Limestone
233		Tangentially-fired	Wet Limestone
234		Tangentially-fired	Wet Limestone
235		Tangentially-fired	Wet Limestone
236		Tangentially-fired	Wet Limestone
237		Tangentially-fired	Wet Limestone
238		Tangentially-fired	Wet Limestone
239		Tangentially-fired	Wet Limestone
240		Tangentially-fired	Wet Limestone
241		Tangentially-fired	Wet Limestone
242		Tangentially-fired	Wet Limestone
243		Tangentially-fired	Wet Limestone
244		Tangentially-fired	Wet Limestone
245		Tangentially-fired	Wet Limestone
246		Tangentially-fired	Wet Limestone
247		Tangentially-fired	Wet Limestone
248		Tangentially-fired	Wet Limestone
249		Tangentially-fired	Wet Limestone
250		Tangentially-fired	Wet Limestone
251		Tangentially-fired	Wet Limestone
252		Tangentially-fired	Wet Limestone
253		Tangentially-fired	Wet Limestone
254		Tangentially-fired	Wet Limestone
255		Tangentially-fired	Wet Limestone
256		Tangentially-fired	Wet Limestone
257		Tangentially-fired	Wet Limestone
258		Tangentially-fired	Wet Limestone

	S	T	U
259		Tangentially-fired	Wet Limestone
260		Tangentially-fired	Wet Limestone
261		Tangentially-fired	Wet Limestone
262		Tangentially-fired	Wet Limestone
263		Tangentially-fired	Wet Limestone
264		Tangentially-fired	Wet Limestone
265		Tangentially-fired	Wet Limestone
266		Tangentially-fired	Wet Limestone
267		Tangentially-fired	Wet Limestone
268		Tangentially-fired	Wet Limestone
269		Tangentially-fired	Wet Limestone
270		Tangentially-fired	Wet Limestone
271		Tangentially-fired	Wet Limestone
272		Tangentially-fired	Wet Limestone
273		Tangentially-fired	Wet Limestone
274		Tangentially-fired	Wet Limestone
275		Tangentially-fired	Wet Limestone
276		Tangentially-fired	Wet Limestone
277		Tangentially-fired	Wet Limestone
278		Tangentially-fired	Wet Limestone
279		Tangentially-fired	Wet Limestone
280		Tangentially-fired	Wet Limestone
281		Tangentially-fired	Wet Limestone
282		Tangentially-fired	Wet Limestone
283		Tangentially-fired	Wet Limestone
284		Tangentially-fired	Wet Limestone
285		Tangentially-fired	Wet Limestone
286		Tangentially-fired	Wet Limestone
287		Tangentially-fired	Wet Limestone
288		Tangentially-fired	Wet Limestone
289		Tangentially-fired	Wet Limestone
290		Tangentially-fired	Wet Limestone
291		Tangentially-fired	Wet Limestone
292		Tangentially-fired	Wet Limestone
293		Tangentially-fired	Wet Limestone
294		Tangentially-fired	Wet Limestone
295		Tangentially-fired	Wet Limestone
296		Tangentially-fired	Wet Limestone
297		Tangentially-fired	Wet Limestone
298		Tangentially-fired	Wet Limestone
299		Tangentially-fired	Wet Limestone
300		Tangentially-fired	Wet Limestone
301		Tangentially-fired	Wet Limestone

	S	T	U
302		Tangentially-fired	Wet Limestone
303		Tangentially-fired	Wet Limestone
304		Tangentially-fired	Wet Limestone
305		Tangentially-fired	Wet Limestone
306		Tangentially-fired	Wet Limestone
307		Tangentially-fired	Wet Limestone
308		Tangentially-fired	Wet Limestone
309		Tangentially-fired	Wet Limestone
310		Tangentially-fired	Wet Limestone
311		Tangentially-fired	Wet Limestone
312		Tangentially-fired	Wet Limestone
313		Tangentially-fired	Wet Limestone
314		Tangentially-fired	Wet Limestone
315		Tangentially-fired	Wet Limestone
316		Tangentially-fired	Wet Limestone
317		Tangentially-fired	Wet Limestone
318		Tangentially-fired	Wet Limestone
319		Tangentially-fired	Wet Limestone
320		Tangentially-fired	Wet Limestone
321		Tangentially-fired	Wet Limestone
322		Tangentially-fired	Wet Limestone
323		Tangentially-fired	Wet Limestone
324		Tangentially-fired	Wet Limestone
325		Tangentially-fired	Wet Limestone
326		Tangentially-fired	Wet Limestone
327		Tangentially-fired	Wet Limestone
328		Tangentially-fired	Wet Limestone
329		Tangentially-fired	Wet Limestone
330		Tangentially-fired	Wet Limestone
331		Tangentially-fired	Wet Limestone
332		Tangentially-fired	Wet Limestone
333		Tangentially-fired	Wet Limestone
334		Tangentially-fired	Wet Limestone
335		Tangentially-fired	Wet Limestone
336		Tangentially-fired	Wet Limestone
337		Tangentially-fired	Wet Limestone
338		Tangentially-fired	Wet Limestone
339		Tangentially-fired	Wet Limestone
340		Tangentially-fired	Wet Limestone
341		Tangentially-fired	Wet Limestone
342		Tangentially-fired	Wet Limestone
343		Tangentially-fired	Wet Limestone
344		Tangentially-fired	Wet Limestone

	S	T	U
345		Tangentially-fired	Wet Limestone
346		Tangentially-fired	Wet Limestone
347		Tangentially-fired	Wet Limestone
348		Tangentially-fired	Wet Limestone
349		Tangentially-fired	Wet Limestone
350		Tangentially-fired	Wet Limestone
351		Tangentially-fired	Wet Limestone
352		Tangentially-fired	Wet Limestone
353		Tangentially-fired	Wet Limestone
354		Tangentially-fired	Wet Limestone
355		Tangentially-fired	Wet Limestone
356		Tangentially-fired	Wet Limestone
357		Tangentially-fired	Wet Limestone
358		Tangentially-fired	Wet Limestone
359		Tangentially-fired	Wet Limestone
360		Tangentially-fired	Wet Limestone
361		Tangentially-fired	Wet Limestone
362		Tangentially-fired	Wet Limestone
363		Tangentially-fired	Wet Limestone
364		Tangentially-fired	Wet Limestone
365		Tangentially-fired	Wet Limestone
366		Tangentially-fired	Wet Limestone
367		Tangentially-fired	Wet Limestone
368		Tangentially-fired	Wet Limestone
369		Tangentially-fired	Wet Limestone
370		Tangentially-fired	Wet Limestone
371		Tangentially-fired	Wet Limestone
372		Tangentially-fired	Wet Limestone
373		Tangentially-fired	Wet Limestone
374		Tangentially-fired	Wet Limestone
375		Tangentially-fired	Wet Limestone
376		Tangentially-fired	Wet Limestone
377		Tangentially-fired	Wet Limestone
378		Tangentially-fired	Wet Limestone
379		Tangentially-fired	Wet Limestone
380		Tangentially-fired	Wet Limestone
381		Tangentially-fired	Wet Limestone
382		Tangentially-fired	Wet Limestone
383		Tangentially-fired	Wet Limestone
384		Tangentially-fired	Wet Limestone
385		Tangentially-fired	Wet Limestone
386		Tangentially-fired	Wet Limestone
387		Tangentially-fired	Wet Limestone

	S	T	U
388		Tangentially-fired	Wet Limestone
389		Tangentially-fired	Wet Limestone
390		Tangentially-fired	Wet Limestone
391		Tangentially-fired	Wet Limestone
392		Tangentially-fired	Wet Limestone
393		Tangentially-fired	Wet Limestone
394		Tangentially-fired	Wet Limestone
395		Tangentially-fired	Wet Limestone
396		Tangentially-fired	Wet Limestone
397		Tangentially-fired	Wet Limestone
398		Tangentially-fired	Wet Limestone
399		Tangentially-fired	Wet Limestone
400		Tangentially-fired	Wet Limestone
401		Tangentially-fired	Wet Limestone
402		Tangentially-fired	Wet Limestone
403		Tangentially-fired	Wet Limestone
404		Tangentially-fired	Wet Limestone
405		Tangentially-fired	Wet Limestone
406		Tangentially-fired	Wet Limestone
407		Tangentially-fired	Wet Limestone
408		Tangentially-fired	Wet Limestone
409		Tangentially-fired	Wet Limestone
410		Tangentially-fired	Wet Limestone
411		Tangentially-fired	Wet Limestone
412		Tangentially-fired	Wet Limestone
413		Tangentially-fired	Wet Limestone
414		Tangentially-fired	Wet Limestone
415		Tangentially-fired	Wet Limestone
416		Tangentially-fired	Wet Limestone
417		Tangentially-fired	Wet Limestone
418		Tangentially-fired	Wet Limestone
419		Tangentially-fired	Wet Limestone
420		Tangentially-fired	Wet Limestone
421		Tangentially-fired	Wet Limestone
422		Tangentially-fired	Wet Limestone
423		Tangentially-fired	Wet Limestone
424		Tangentially-fired	Wet Limestone
425		Tangentially-fired	Wet Limestone
426		Tangentially-fired	Wet Limestone
427		Tangentially-fired	Wet Limestone
428		Tangentially-fired	Wet Limestone
429		Tangentially-fired	Wet Limestone
430		Tangentially-fired	Wet Limestone

	S	T	U
431		Tangentially-fired	Wet Limestone
432		Tangentially-fired	Wet Limestone
433		Tangentially-fired	Wet Limestone
434		Tangentially-fired	Wet Limestone
435		Tangentially-fired	Wet Limestone
436		Tangentially-fired	Wet Limestone
437		Tangentially-fired	Wet Limestone
438		Tangentially-fired	Wet Limestone
439		Tangentially-fired	Wet Limestone
440		Tangentially-fired	Wet Limestone
441		Tangentially-fired	Wet Limestone
442		Tangentially-fired	Wet Limestone
443		Tangentially-fired	Wet Limestone
444		Tangentially-fired	Wet Limestone
445		Tangentially-fired	Wet Limestone
446		Tangentially-fired	Wet Limestone
447		Tangentially-fired	Wet Limestone
448		Tangentially-fired	Wet Limestone
449		Tangentially-fired	Wet Limestone
450		Tangentially-fired	Wet Limestone
451		Tangentially-fired	Wet Limestone
452		Tangentially-fired	Wet Limestone
453		Tangentially-fired	Wet Limestone
454		Tangentially-fired	Wet Limestone
455		Tangentially-fired	Wet Limestone
456		Tangentially-fired	Wet Limestone
457		Tangentially-fired	Wet Limestone
458		Tangentially-fired	Wet Limestone
459		Tangentially-fired	Wet Limestone
460		Tangentially-fired	Wet Limestone
461		Tangentially-fired	Wet Limestone
462		Tangentially-fired	Wet Limestone
463		Tangentially-fired	Wet Limestone
464		Tangentially-fired	Wet Limestone
465		Tangentially-fired	Wet Limestone
466		Tangentially-fired	Wet Limestone
467		Tangentially-fired	Wet Limestone
468		Tangentially-fired	Wet Limestone
469		Tangentially-fired	Wet Limestone
470		Tangentially-fired	Wet Limestone
471		Tangentially-fired	Wet Limestone
472		Tangentially-fired	Wet Limestone
473		Tangentially-fired	Wet Limestone

	S	T	U
474		Tangentially-fired	Wet Limestone
475		Tangentially-fired	Wet Limestone
476		Tangentially-fired	Wet Limestone
477		Tangentially-fired	Wet Limestone
478		Tangentially-fired	Wet Limestone
479		Tangentially-fired	Wet Limestone
480		Tangentially-fired	Wet Limestone
481		Tangentially-fired	Wet Limestone
482		Tangentially-fired	Wet Limestone
483		Tangentially-fired	Wet Limestone
484		Tangentially-fired	Wet Limestone
485		Tangentially-fired	Wet Limestone
486		Tangentially-fired	Wet Limestone
487		Tangentially-fired	Wet Limestone
488		Tangentially-fired	Wet Limestone
489		Tangentially-fired	Wet Limestone
490		Tangentially-fired	Wet Limestone
491		Tangentially-fired	Wet Limestone
492		Tangentially-fired	Wet Limestone
493		Tangentially-fired	Wet Limestone
494		Tangentially-fired	Wet Limestone
495		Tangentially-fired	Wet Limestone
496		Tangentially-fired	Wet Limestone
497		Tangentially-fired	Wet Limestone
498		Tangentially-fired	Wet Limestone
499		Tangentially-fired	Wet Limestone
500		Tangentially-fired	Wet Limestone
501		Tangentially-fired	Wet Limestone
502		Tangentially-fired	Wet Limestone
503		Tangentially-fired	Wet Limestone
504		Tangentially-fired	Wet Limestone
505		Tangentially-fired	Wet Limestone
506		Tangentially-fired	Wet Limestone
507		Tangentially-fired	Wet Limestone
508		Tangentially-fired	Wet Limestone
509		Tangentially-fired	Wet Limestone
510		Tangentially-fired	Wet Limestone
511		Tangentially-fired	Wet Limestone
512		Tangentially-fired	Wet Limestone
513		Tangentially-fired	Wet Limestone
514		Tangentially-fired	Wet Limestone
515		Tangentially-fired	Wet Limestone
516		Tangentially-fired	Wet Limestone

	S	T	U
517		Tangentially-fired	Wet Limestone
518		Tangentially-fired	Wet Limestone
519		Tangentially-fired	Wet Limestone
520		Tangentially-fired	Wet Limestone
521		Tangentially-fired	Wet Limestone
522		Tangentially-fired	Wet Limestone
523		Tangentially-fired	Wet Limestone
524		Tangentially-fired	Wet Limestone
525		Tangentially-fired	Wet Limestone
526		Tangentially-fired	Wet Limestone
527		Tangentially-fired	Wet Limestone
528		Tangentially-fired	Wet Limestone
529		Tangentially-fired	Wet Limestone
530		Tangentially-fired	Wet Limestone
531		Tangentially-fired	Wet Limestone
532		Tangentially-fired	Wet Limestone
533		Tangentially-fired	Wet Limestone
534		Tangentially-fired	Wet Limestone
535		Tangentially-fired	Wet Limestone
536		Tangentially-fired	Wet Limestone
537		Tangentially-fired	Wet Limestone
538		Tangentially-fired	Wet Limestone
539		Tangentially-fired	Wet Limestone
540		Tangentially-fired	Wet Limestone
541		Tangentially-fired	Wet Limestone
542		Tangentially-fired	Wet Limestone
543		Tangentially-fired	Wet Limestone
544		Tangentially-fired	Wet Limestone
545		Tangentially-fired	Wet Limestone
546		Tangentially-fired	Wet Limestone
547		Tangentially-fired	Wet Limestone
548		Tangentially-fired	Wet Limestone
549		Tangentially-fired	Wet Limestone
550		Tangentially-fired	Wet Limestone
551		Tangentially-fired	Wet Limestone
552		Tangentially-fired	Wet Limestone
553		Tangentially-fired	Wet Limestone
554		Tangentially-fired	Wet Limestone
555		Tangentially-fired	Wet Limestone
556		Tangentially-fired	Wet Limestone
557		Tangentially-fired	Wet Limestone
558		Tangentially-fired	Wet Limestone
559		Tangentially-fired	Wet Limestone

	S	T	U
560		Tangentially-fired	Wet Limestone
561		Tangentially-fired	Wet Limestone
562		Tangentially-fired	Wet Limestone
563		Tangentially-fired	Wet Limestone
564		Tangentially-fired	Wet Limestone
565		Tangentially-fired	Wet Limestone
566		Tangentially-fired	Wet Limestone
567		Tangentially-fired	Wet Limestone
568		Tangentially-fired	Wet Limestone
569		Tangentially-fired	Wet Limestone
570		Tangentially-fired	Wet Limestone
571		Tangentially-fired	Wet Limestone
572		Tangentially-fired	Wet Limestone
573		Tangentially-fired	Wet Limestone
574		Tangentially-fired	Wet Limestone
575		Tangentially-fired	Wet Limestone
576		Tangentially-fired	Wet Limestone
577		Tangentially-fired	Wet Limestone
578		Tangentially-fired	Wet Limestone
579		Tangentially-fired	Wet Limestone
580		Tangentially-fired	Wet Limestone
581		Tangentially-fired	Wet Limestone
582		Tangentially-fired	Wet Limestone
583		Tangentially-fired	Wet Limestone
584		Tangentially-fired	Wet Limestone
585		Tangentially-fired	Wet Limestone
586		Tangentially-fired	Wet Limestone
587		Tangentially-fired	Wet Limestone
588		Tangentially-fired	Wet Limestone
589		Tangentially-fired	Wet Limestone
590		Tangentially-fired	Wet Limestone
591		Tangentially-fired	Wet Limestone
592		Tangentially-fired	Wet Limestone
593		Tangentially-fired	Wet Limestone
594		Tangentially-fired	Wet Limestone
595		Tangentially-fired	Wet Limestone
596		Tangentially-fired	Wet Limestone
597		Tangentially-fired	Wet Limestone
598		Tangentially-fired	Wet Limestone
599		Tangentially-fired	Wet Limestone
600		Tangentially-fired	Wet Limestone
601		Tangentially-fired	Wet Limestone
602		Tangentially-fired	Wet Limestone

	S	T	U
603		Tangentially-fired	Wet Limestone
604		Tangentially-fired	Wet Limestone
605		Tangentially-fired	Wet Limestone
606		Tangentially-fired	Wet Limestone
607		Tangentially-fired	Wet Limestone
608		Tangentially-fired	Wet Limestone
609		Tangentially-fired	Wet Limestone
610		Tangentially-fired	Wet Limestone
611		Tangentially-fired	Wet Limestone
612		Tangentially-fired	Wet Limestone
613		Tangentially-fired	Wet Limestone
614		Tangentially-fired	Wet Limestone
615		Tangentially-fired	Wet Limestone
616		Tangentially-fired	Wet Limestone
617		Tangentially-fired	Wet Limestone
618		Tangentially-fired	Wet Limestone
619		Tangentially-fired	Wet Limestone
620		Tangentially-fired	Wet Limestone
621		Tangentially-fired	Wet Limestone
622		Tangentially-fired	Wet Limestone
623		Tangentially-fired	Wet Limestone
624		Tangentially-fired	Wet Limestone
625		Tangentially-fired	Wet Limestone
626		Tangentially-fired	Wet Limestone
627		Tangentially-fired	Wet Limestone
628		Tangentially-fired	Wet Limestone
629		Tangentially-fired	Wet Limestone
630		Tangentially-fired	Wet Limestone
631		Tangentially-fired	Wet Limestone
632		Tangentially-fired	Wet Limestone
633		Tangentially-fired	Wet Limestone
634		Tangentially-fired	Wet Limestone
635		Tangentially-fired	Wet Limestone
636		Tangentially-fired	Wet Limestone
637		Tangentially-fired	Wet Limestone
638		Tangentially-fired	Wet Limestone
639		Tangentially-fired	Wet Limestone
640		Tangentially-fired	Wet Limestone
641		Tangentially-fired	Wet Limestone
642		Tangentially-fired	Wet Limestone
643		Tangentially-fired	Wet Limestone
644		Tangentially-fired	Wet Limestone
645		Tangentially-fired	Wet Limestone

	S	T	U
646		Tangentially-fired	Wet Limestone
647		Tangentially-fired	Wet Limestone
648		Tangentially-fired	Wet Limestone
649		Tangentially-fired	Wet Limestone
650		Tangentially-fired	Wet Limestone
651		Tangentially-fired	Wet Limestone
652		Tangentially-fired	Wet Limestone
653		Tangentially-fired	Wet Limestone
654		Tangentially-fired	Wet Limestone
655		Tangentially-fired	Wet Limestone
656		Tangentially-fired	Wet Limestone
657		Tangentially-fired	Wet Limestone
658		Tangentially-fired	Wet Limestone
659		Tangentially-fired	Wet Limestone
660		Tangentially-fired	Wet Limestone
661		Tangentially-fired	Wet Limestone
662		Tangentially-fired	Wet Limestone
663		Tangentially-fired	Wet Limestone
664		Tangentially-fired	Wet Limestone
665		Tangentially-fired	Wet Limestone
666		Tangentially-fired	Wet Limestone
667		Tangentially-fired	Wet Limestone
668		Tangentially-fired	Wet Limestone
669		Tangentially-fired	Wet Limestone
670		Tangentially-fired	Wet Limestone
671		Tangentially-fired	Wet Limestone
672		Tangentially-fired	Wet Limestone
673		Tangentially-fired	Wet Limestone
674		Tangentially-fired	Wet Limestone
675		Tangentially-fired	Wet Limestone
676		Tangentially-fired	Wet Limestone
677		Tangentially-fired	Wet Limestone
678		Tangentially-fired	Wet Limestone
679		Tangentially-fired	Wet Limestone
680		Tangentially-fired	Wet Limestone
681		Tangentially-fired	Wet Limestone
682		Tangentially-fired	Wet Limestone
683		Tangentially-fired	Wet Limestone
684		Tangentially-fired	Wet Limestone
685		Tangentially-fired	Wet Limestone
686		Tangentially-fired	Wet Limestone
687		Tangentially-fired	Wet Limestone
688		Tangentially-fired	Wet Limestone

	S	T	U
689		Tangentially-fired	Wet Limestone
690		Tangentially-fired	Wet Limestone
691		Tangentially-fired	Wet Limestone
692		Tangentially-fired	Wet Limestone
693		Tangentially-fired	Wet Limestone
694		Tangentially-fired	Wet Limestone
695		Tangentially-fired	Wet Limestone
696		Tangentially-fired	Wet Limestone
697		Tangentially-fired	Wet Limestone
698		Tangentially-fired	Wet Limestone
699		Tangentially-fired	Wet Limestone
700		Tangentially-fired	Wet Limestone
701		Tangentially-fired	Wet Limestone
702		Tangentially-fired	Wet Limestone
703		Tangentially-fired	Wet Limestone
704		Tangentially-fired	Wet Limestone
705		Tangentially-fired	Wet Limestone
706		Tangentially-fired	Wet Limestone
707		Tangentially-fired	Wet Limestone
708		Tangentially-fired	Wet Limestone
709		Tangentially-fired	Wet Limestone
710		Tangentially-fired	Wet Limestone
711		Tangentially-fired	Wet Limestone
712		Tangentially-fired	Wet Limestone
713		Tangentially-fired	Wet Limestone
714		Tangentially-fired	Wet Limestone
715		Tangentially-fired	Wet Limestone
716		Tangentially-fired	Wet Limestone
717		Tangentially-fired	Wet Limestone
718		Tangentially-fired	Wet Limestone
719		Tangentially-fired	Wet Limestone
720		Tangentially-fired	Wet Limestone
721		Tangentially-fired	Wet Limestone
722		Tangentially-fired	Wet Limestone
723		Tangentially-fired	Wet Limestone
724		Tangentially-fired	Wet Limestone
725		Tangentially-fired	Wet Limestone
726		Tangentially-fired	Wet Limestone
727		Tangentially-fired	Wet Limestone
728		Tangentially-fired	Wet Limestone
729		Tangentially-fired	Wet Limestone
730		Tangentially-fired	Wet Limestone
731		Tangentially-fired	Wet Limestone

	S	T	U
732		Tangentially-fired	Wet Limestone
733		Tangentially-fired	Wet Limestone
734		Tangentially-fired	Wet Limestone
735		Tangentially-fired	Wet Limestone
736		Tangentially-fired	Wet Limestone
737		Tangentially-fired	Wet Limestone
738		Tangentially-fired	Wet Limestone
739		Tangentially-fired	Wet Limestone
740		Tangentially-fired	Wet Limestone
741		Tangentially-fired	Wet Limestone
742		Tangentially-fired	Wet Limestone
743		Tangentially-fired	Wet Limestone
744		Tangentially-fired	Wet Limestone
745		Tangentially-fired	Wet Limestone
746		Tangentially-fired	Wet Limestone
747		Tangentially-fired	Wet Limestone
748		Tangentially-fired	Wet Limestone
749		Tangentially-fired	Wet Limestone
750		Tangentially-fired	Wet Limestone
751		Tangentially-fired	Wet Limestone
752		Tangentially-fired	Wet Limestone
753		Tangentially-fired	Wet Limestone
754		Tangentially-fired	Wet Limestone
755		Tangentially-fired	Wet Limestone
756		Tangentially-fired	Wet Limestone
757		Tangentially-fired	Wet Limestone
758		Tangentially-fired	Wet Limestone
759		Tangentially-fired	Wet Limestone
760		Tangentially-fired	Wet Limestone
761		Tangentially-fired	Wet Limestone
762		Tangentially-fired	Wet Limestone
763		Tangentially-fired	Wet Limestone
764		Tangentially-fired	Wet Limestone
765		Tangentially-fired	Wet Limestone
766		Tangentially-fired	Wet Limestone
767		Tangentially-fired	Wet Limestone
768		Tangentially-fired	Wet Limestone
769		Tangentially-fired	Wet Limestone
770		Tangentially-fired	Wet Limestone
771		Tangentially-fired	Wet Limestone
772		Tangentially-fired	Wet Limestone
773		Tangentially-fired	Wet Limestone
774		Tangentially-fired	Wet Limestone

	S	T	U
775		Tangentially-fired	Wet Limestone
776		Tangentially-fired	Wet Limestone
777		Tangentially-fired	Wet Limestone
778		Tangentially-fired	Wet Limestone
779		Tangentially-fired	Wet Limestone
780		Tangentially-fired	Wet Limestone
781		Tangentially-fired	Wet Limestone
782		Tangentially-fired	Wet Limestone
783		Tangentially-fired	Wet Limestone
784		Tangentially-fired	Wet Limestone
785		Tangentially-fired	Wet Limestone
786		Tangentially-fired	Wet Limestone
787		Tangentially-fired	Wet Limestone
788		Tangentially-fired	Wet Limestone
789		Tangentially-fired	Wet Limestone
790		Tangentially-fired	Wet Limestone
791		Tangentially-fired	Wet Limestone
792		Tangentially-fired	Wet Limestone
793		Tangentially-fired	Wet Limestone
794		Tangentially-fired	Wet Limestone
795		Tangentially-fired	Wet Limestone
796		Tangentially-fired	Wet Limestone
797		Tangentially-fired	Wet Limestone
798		Tangentially-fired	Wet Limestone
799		Tangentially-fired	Wet Limestone
800		Tangentially-fired	Wet Limestone
801		Tangentially-fired	Wet Limestone
802		Tangentially-fired	Wet Limestone
803		Tangentially-fired	Wet Limestone
804		Tangentially-fired	Wet Limestone
805		Tangentially-fired	Wet Limestone
806		Tangentially-fired	Wet Limestone
807		Tangentially-fired	Wet Limestone
808		Tangentially-fired	Wet Limestone
809		Tangentially-fired	Wet Limestone
810		Tangentially-fired	Wet Limestone
811		Tangentially-fired	Wet Limestone
812		Tangentially-fired	Wet Limestone
813		Tangentially-fired	Wet Limestone
814		Tangentially-fired	Wet Limestone
815		Tangentially-fired	Wet Limestone
816		Tangentially-fired	Wet Limestone
817		Tangentially-fired	Wet Limestone

	S	T	U
818		Tangentially-fired	Wet Limestone
819		Tangentially-fired	Wet Limestone
820		Tangentially-fired	Wet Limestone
821		Tangentially-fired	Wet Limestone
822		Tangentially-fired	Wet Limestone
823		Tangentially-fired	Wet Limestone
824		Tangentially-fired	Wet Limestone
825		Tangentially-fired	Wet Limestone
826		Tangentially-fired	Wet Limestone
827		Tangentially-fired	Wet Limestone
828		Tangentially-fired	Wet Limestone
829		Tangentially-fired	Wet Limestone
830		Tangentially-fired	Wet Limestone
831		Tangentially-fired	Wet Limestone
832		Tangentially-fired	Wet Limestone
833		Tangentially-fired	Wet Limestone
834		Tangentially-fired	Wet Limestone
835		Tangentially-fired	Wet Limestone
836		Tangentially-fired	Wet Limestone
837		Tangentially-fired	Wet Limestone
838		Tangentially-fired	Wet Limestone
839		Tangentially-fired	Wet Limestone
840		Tangentially-fired	Wet Limestone
841		Tangentially-fired	Wet Limestone
842		Tangentially-fired	Wet Limestone
843		Tangentially-fired	Wet Limestone
844		Tangentially-fired	Wet Limestone
845		Tangentially-fired	Wet Limestone
846		Tangentially-fired	Wet Limestone
847		Tangentially-fired	Wet Limestone
848		Tangentially-fired	Wet Limestone
849		Tangentially-fired	Wet Limestone
850		Tangentially-fired	Wet Limestone
851		Tangentially-fired	Wet Limestone
852		Tangentially-fired	Wet Limestone
853		Tangentially-fired	Wet Limestone
854		Tangentially-fired	Wet Limestone
855		Tangentially-fired	Wet Limestone
856		Tangentially-fired	Wet Limestone
857		Tangentially-fired	Wet Limestone
858		Tangentially-fired	Wet Limestone
859		Tangentially-fired	Wet Limestone
860		Tangentially-fired	Wet Limestone

	S	T	U
861		Tangentially-fired	Wet Limestone
862		Tangentially-fired	Wet Limestone
863		Tangentially-fired	Wet Limestone
864		Tangentially-fired	Wet Limestone
865		Tangentially-fired	Wet Limestone
866		Tangentially-fired	Wet Limestone
867		Tangentially-fired	Wet Limestone
868		Tangentially-fired	Wet Limestone
869		Tangentially-fired	Wet Limestone
870		Tangentially-fired	Wet Limestone
871		Tangentially-fired	Wet Limestone
872		Tangentially-fired	Wet Limestone
873		Tangentially-fired	Wet Limestone
874		Tangentially-fired	Wet Limestone
875		Tangentially-fired	Wet Limestone
876		Tangentially-fired	Wet Limestone
877		Tangentially-fired	Wet Limestone
878		Tangentially-fired	Wet Limestone
879		Tangentially-fired	Wet Limestone
880		Tangentially-fired	Wet Limestone
881		Tangentially-fired	Wet Limestone
882		Tangentially-fired	Wet Limestone
883		Tangentially-fired	Wet Limestone
884		Tangentially-fired	Wet Limestone
885		Tangentially-fired	Wet Limestone
886		Tangentially-fired	Wet Limestone
887		Tangentially-fired	Wet Limestone
888		Tangentially-fired	Wet Limestone
889		Tangentially-fired	Wet Limestone
890		Tangentially-fired	Wet Limestone
891		Tangentially-fired	Wet Limestone
892		Tangentially-fired	Wet Limestone
893		Tangentially-fired	Wet Limestone
894		Tangentially-fired	Wet Limestone
895		Tangentially-fired	Wet Limestone
896		Tangentially-fired	Wet Limestone
897		Tangentially-fired	Wet Limestone
898		Tangentially-fired	Wet Limestone
899		Tangentially-fired	Wet Limestone
900		Tangentially-fired	Wet Limestone
901		Tangentially-fired	Wet Limestone
902		Tangentially-fired	Wet Limestone
903		Tangentially-fired	Wet Limestone

	S	T	U
904		Tangentially-fired	Wet Limestone
905		Tangentially-fired	Wet Limestone
906		Tangentially-fired	Wet Limestone
907		Tangentially-fired	Wet Limestone
908		Tangentially-fired	Wet Limestone
909		Tangentially-fired	Wet Limestone
910		Tangentially-fired	Wet Limestone
911		Tangentially-fired	Wet Limestone
912		Tangentially-fired	Wet Limestone
913		Tangentially-fired	Wet Limestone
914		Tangentially-fired	Wet Limestone
915		Tangentially-fired	Wet Limestone
916		Tangentially-fired	Wet Limestone
917		Tangentially-fired	Wet Limestone
918		Tangentially-fired	Wet Limestone
919		Tangentially-fired	Wet Limestone
920		Tangentially-fired	Wet Limestone
921		Tangentially-fired	Wet Limestone
922		Tangentially-fired	Wet Limestone
923		Tangentially-fired	Wet Limestone
924		Tangentially-fired	Wet Limestone
925		Tangentially-fired	Wet Limestone
926		Tangentially-fired	Wet Limestone
927		Tangentially-fired	Wet Limestone
928		Tangentially-fired	Wet Limestone
929		Tangentially-fired	Wet Limestone
930		Tangentially-fired	Wet Limestone
931		Tangentially-fired	Wet Limestone
932		Tangentially-fired	Wet Limestone
933		Tangentially-fired	Wet Limestone
934		Tangentially-fired	Wet Limestone
935		Tangentially-fired	Wet Limestone
936		Tangentially-fired	Wet Limestone
937		Tangentially-fired	Wet Limestone
938		Tangentially-fired	Wet Limestone
939		Tangentially-fired	Wet Limestone
940		Tangentially-fired	Wet Limestone
941		Tangentially-fired	Wet Limestone
942		Tangentially-fired	Wet Limestone
943		Tangentially-fired	Wet Limestone
944		Tangentially-fired	Wet Limestone
945		Tangentially-fired	Wet Limestone
946		Tangentially-fired	Wet Limestone

	S	T	U
947		Tangentially-fired	Wet Limestone
948		Tangentially-fired	Wet Limestone
949		Tangentially-fired	Wet Limestone
950		Tangentially-fired	Wet Limestone
951		Tangentially-fired	Wet Limestone
952		Tangentially-fired	Wet Limestone
953		Tangentially-fired	Wet Limestone
954		Tangentially-fired	Wet Limestone
955		Tangentially-fired	Wet Limestone
956		Tangentially-fired	Wet Limestone
957		Tangentially-fired	Wet Limestone
958		Tangentially-fired	Wet Limestone
959		Tangentially-fired	Wet Limestone
960		Tangentially-fired	Wet Limestone
961		Tangentially-fired	Wet Limestone
962		Tangentially-fired	Wet Limestone
963		Tangentially-fired	Wet Limestone
964		Tangentially-fired	Wet Limestone
965		Tangentially-fired	Wet Limestone
966		Tangentially-fired	Wet Limestone
967		Tangentially-fired	Wet Limestone
968		Tangentially-fired	Wet Limestone
969		Tangentially-fired	Wet Limestone
970		Tangentially-fired	Wet Limestone
971		Tangentially-fired	Wet Limestone
972		Tangentially-fired	Wet Limestone
973		Tangentially-fired	Wet Limestone
974		Tangentially-fired	Wet Limestone
975		Tangentially-fired	Wet Limestone
976		Tangentially-fired	Wet Limestone
977		Tangentially-fired	Wet Limestone
978		Tangentially-fired	Wet Limestone
979		Tangentially-fired	Wet Limestone
980		Tangentially-fired	Wet Limestone
981		Tangentially-fired	Wet Limestone
982		Tangentially-fired	Wet Limestone
983		Tangentially-fired	Wet Limestone
984		Tangentially-fired	Wet Limestone
985		Tangentially-fired	Wet Limestone
986		Tangentially-fired	Wet Limestone
987		Tangentially-fired	Wet Limestone
988		Tangentially-fired	Wet Limestone
989		Tangentially-fired	Wet Limestone

	S	T	U
990		Tangentially-fired	Wet Limestone
991		Tangentially-fired	Wet Limestone
992		Tangentially-fired	Wet Limestone
993		Tangentially-fired	Wet Limestone
994		Tangentially-fired	Wet Limestone
995		Tangentially-fired	Wet Limestone
996		Tangentially-fired	Wet Limestone
997		Tangentially-fired	Wet Limestone
998		Tangentially-fired	Wet Limestone
999		Tangentially-fired	Wet Limestone
1000		Tangentially-fired	Wet Limestone
1001		Tangentially-fired	Wet Limestone
1002		Tangentially-fired	Wet Limestone
1003		Tangentially-fired	Wet Limestone
1004		Tangentially-fired	Wet Limestone
1005		Tangentially-fired	Wet Limestone
1006		Tangentially-fired	Wet Limestone
1007		Tangentially-fired	Wet Limestone
1008		Tangentially-fired	Wet Limestone
1009		Tangentially-fired	Wet Limestone
1010		Tangentially-fired	Wet Limestone
1011		Tangentially-fired	Wet Limestone
1012		Tangentially-fired	Wet Limestone
1013		Tangentially-fired	Wet Limestone
1014		Tangentially-fired	Wet Limestone
1015		Tangentially-fired	Wet Limestone
1016		Tangentially-fired	Wet Limestone
1017		Tangentially-fired	Wet Limestone
1018		Tangentially-fired	Wet Limestone
1019		Tangentially-fired	Wet Limestone
1020		Tangentially-fired	Wet Limestone
1021		Tangentially-fired	Wet Limestone
1022		Tangentially-fired	Wet Limestone
1023		Tangentially-fired	Wet Limestone
1024		Tangentially-fired	Wet Limestone
1025		Tangentially-fired	Wet Limestone
1026		Tangentially-fired	Wet Limestone
1027		Tangentially-fired	Wet Limestone
1028		Tangentially-fired	Wet Limestone
1029		Tangentially-fired	Wet Limestone
1030		Tangentially-fired	Wet Limestone
1031		Tangentially-fired	Wet Limestone
1032		Tangentially-fired	Wet Limestone

	S	T	U
1033		Tangentially-fired	Wet Limestone
1034		Tangentially-fired	Wet Limestone
1035		Tangentially-fired	Wet Limestone
1036		Tangentially-fired	Wet Limestone
1037		Tangentially-fired	Wet Limestone
1038		Tangentially-fired	Wet Limestone
1039		Tangentially-fired	Wet Limestone
1040		Tangentially-fired	Wet Limestone
1041		Tangentially-fired	Wet Limestone
1042		Tangentially-fired	Wet Limestone
1043		Tangentially-fired	Wet Limestone
1044		Tangentially-fired	Wet Limestone
1045		Tangentially-fired	Wet Limestone
1046		Tangentially-fired	Wet Limestone
1047		Tangentially-fired	Wet Limestone
1048		Tangentially-fired	Wet Limestone
1049		Tangentially-fired	Wet Limestone
1050		Tangentially-fired	Wet Limestone
1051		Tangentially-fired	Wet Limestone
1052		Tangentially-fired	Wet Limestone
1053		Tangentially-fired	Wet Limestone
1054		Tangentially-fired	Wet Limestone
1055		Tangentially-fired	Wet Limestone
1056		Tangentially-fired	Wet Limestone
1057		Tangentially-fired	Wet Limestone
1058		Tangentially-fired	Wet Limestone
1059		Tangentially-fired	Wet Limestone
1060		Tangentially-fired	Wet Limestone
1061		Tangentially-fired	Wet Limestone
1062		Tangentially-fired	Wet Limestone
1063		Tangentially-fired	Wet Limestone
1064		Tangentially-fired	Wet Limestone
1065		Tangentially-fired	Wet Limestone
1066		Tangentially-fired	Wet Limestone
1067		Tangentially-fired	Wet Limestone
1068		Tangentially-fired	Wet Limestone
1069		Tangentially-fired	Wet Limestone
1070		Tangentially-fired	Wet Limestone
1071		Tangentially-fired	Wet Limestone
1072		Tangentially-fired	Wet Limestone
1073		Tangentially-fired	Wet Limestone
1074		Tangentially-fired	Wet Limestone
1075		Tangentially-fired	Wet Limestone

	S	T	U
1076		Tangentially-fired	Wet Limestone
1077		Tangentially-fired	Wet Limestone
1078		Tangentially-fired	Wet Limestone
1079		Tangentially-fired	Wet Limestone
1080		Tangentially-fired	Wet Limestone
1081		Tangentially-fired	Wet Limestone
1082		Tangentially-fired	Wet Limestone
1083		Tangentially-fired	Wet Limestone
1084		Tangentially-fired	Wet Limestone
1085		Tangentially-fired	Wet Limestone
1086		Tangentially-fired	Wet Limestone
1087		Tangentially-fired	Wet Limestone
1088		Tangentially-fired	Wet Limestone
1089		Tangentially-fired	Wet Limestone
1090		Tangentially-fired	Wet Limestone
1091		Tangentially-fired	Wet Limestone
1092		Tangentially-fired	Wet Limestone
1093		Tangentially-fired	Wet Limestone
1094		Tangentially-fired	Wet Limestone
1095		Tangentially-fired	Wet Limestone
1096		Tangentially-fired	Wet Limestone
1097		Tangentially-fired	Wet Limestone
1098		Tangentially-fired	Wet Limestone
1099		Tangentially-fired	Wet Limestone
1100		Tangentially-fired	Wet Limestone
1101		Tangentially-fired	Wet Limestone
1102		Tangentially-fired	Wet Limestone
1103		Tangentially-fired	Wet Limestone
1104		Tangentially-fired	Wet Limestone
1105		Tangentially-fired	Wet Limestone
1106		Tangentially-fired	Wet Limestone
1107		Tangentially-fired	Wet Limestone
1108		Tangentially-fired	Wet Limestone
1109		Tangentially-fired	Wet Limestone
1110		Tangentially-fired	Wet Limestone
1111		Tangentially-fired	Wet Limestone
1112		Tangentially-fired	Wet Limestone
1113		Tangentially-fired	Wet Limestone
1114		Tangentially-fired	Wet Limestone
1115		Tangentially-fired	Wet Limestone
1116		Tangentially-fired	Wet Limestone
1117		Tangentially-fired	Wet Limestone
1118		Tangentially-fired	Wet Limestone

	S	T	U
1119		Tangentially-fired	Wet Limestone
1120		Tangentially-fired	Wet Limestone
1121		Tangentially-fired	Wet Limestone
1122		Tangentially-fired	Wet Limestone
1123		Tangentially-fired	Wet Limestone
1124		Tangentially-fired	Wet Limestone
1125		Tangentially-fired	Wet Limestone
1126		Tangentially-fired	Wet Limestone
1127		Tangentially-fired	Wet Limestone
1128		Tangentially-fired	Wet Limestone
1129		Tangentially-fired	Wet Limestone
1130		Tangentially-fired	Wet Limestone
1131		Tangentially-fired	Wet Limestone
1132		Tangentially-fired	Wet Limestone
1133		Tangentially-fired	Wet Limestone
1134		Tangentially-fired	Wet Limestone
1135		Tangentially-fired	Wet Limestone
1136		Tangentially-fired	Wet Limestone
1137		Tangentially-fired	Wet Limestone
1138		Tangentially-fired	Wet Limestone
1139		Tangentially-fired	Wet Limestone
1140		Tangentially-fired	Wet Limestone
1141		Tangentially-fired	Wet Limestone
1142		Tangentially-fired	Wet Limestone
1143		Tangentially-fired	Wet Limestone
1144		Tangentially-fired	Wet Limestone
1145		Tangentially-fired	Wet Limestone
1146		Tangentially-fired	Wet Limestone
1147		Tangentially-fired	Wet Limestone
1148		Tangentially-fired	Wet Limestone
1149		Tangentially-fired	Wet Limestone
1150		Tangentially-fired	Wet Limestone
1151		Tangentially-fired	Wet Limestone
1152		Tangentially-fired	Wet Limestone
1153		Tangentially-fired	Wet Limestone
1154		Tangentially-fired	Wet Limestone
1155		Tangentially-fired	Wet Limestone
1156		Tangentially-fired	Wet Limestone
1157		Tangentially-fired	Wet Limestone
1158		Tangentially-fired	Wet Limestone
1159		Tangentially-fired	Wet Limestone
1160		Tangentially-fired	Wet Limestone
1161		Tangentially-fired	Wet Limestone

	S	T	U
1162		Tangentially-fired	Wet Limestone
1163		Tangentially-fired	Wet Limestone
1164		Tangentially-fired	Wet Limestone
1165		Tangentially-fired	Wet Limestone
1166		Tangentially-fired	Wet Limestone
1167		Tangentially-fired	Wet Limestone
1168		Tangentially-fired	Wet Limestone
1169		Tangentially-fired	Wet Limestone
1170		Tangentially-fired	Wet Limestone
1171		Tangentially-fired	Wet Limestone
1172		Tangentially-fired	Wet Limestone
1173		Tangentially-fired	Wet Limestone
1174		Tangentially-fired	Wet Limestone
1175		Tangentially-fired	Wet Limestone
1176		Tangentially-fired	Wet Limestone
1177		Tangentially-fired	Wet Limestone
1178		Tangentially-fired	Wet Limestone
1179		Tangentially-fired	Wet Limestone
1180		Tangentially-fired	Wet Limestone
1181		Tangentially-fired	Wet Limestone
1182		Tangentially-fired	Wet Limestone
1183		Tangentially-fired	Wet Limestone
1184		Tangentially-fired	Wet Limestone
1185		Tangentially-fired	Wet Limestone
1186		Tangentially-fired	Wet Limestone
1187		Tangentially-fired	Wet Limestone
1188		Tangentially-fired	Wet Limestone
1189		Tangentially-fired	Wet Limestone
1190		Tangentially-fired	Wet Limestone
1191		Tangentially-fired	Wet Limestone
1192		Tangentially-fired	Wet Limestone
1193		Tangentially-fired	Wet Limestone
1194		Tangentially-fired	Wet Limestone
1195		Tangentially-fired	Wet Limestone
1196		Tangentially-fired	Wet Limestone
1197		Tangentially-fired	Wet Limestone
1198		Tangentially-fired	Wet Limestone
1199		Tangentially-fired	Wet Limestone
1200		Tangentially-fired	Wet Limestone
1201		Tangentially-fired	Wet Limestone
1202		Tangentially-fired	Wet Limestone
1203		Tangentially-fired	Wet Limestone
1204		Tangentially-fired	Wet Limestone

	S	T	U
1205		Tangentially-fired	Wet Limestone
1206		Tangentially-fired	Wet Limestone
1207		Tangentially-fired	Wet Limestone
1208		Tangentially-fired	Wet Limestone
1209		Tangentially-fired	Wet Limestone
1210		Tangentially-fired	Wet Limestone
1211		Tangentially-fired	Wet Limestone
1212		Tangentially-fired	Wet Limestone
1213		Tangentially-fired	Wet Limestone
1214		Tangentially-fired	Wet Limestone
1215		Tangentially-fired	Wet Limestone
1216		Tangentially-fired	Wet Limestone
1217		Tangentially-fired	Wet Limestone
1218		Tangentially-fired	Wet Limestone
1219		Tangentially-fired	Wet Limestone
1220		Tangentially-fired	Wet Limestone
1221		Tangentially-fired	Wet Limestone
1222		Tangentially-fired	Wet Limestone
1223		Tangentially-fired	Wet Limestone
1224		Tangentially-fired	Wet Limestone
1225		Tangentially-fired	Wet Limestone
1226		Tangentially-fired	Wet Limestone
1227		Tangentially-fired	Wet Limestone
1228		Tangentially-fired	Wet Limestone
1229		Tangentially-fired	Wet Limestone
1230		Tangentially-fired	Wet Limestone
1231		Tangentially-fired	Wet Limestone
1232		Tangentially-fired	Wet Limestone
1233		Tangentially-fired	Wet Limestone
1234		Tangentially-fired	Wet Limestone
1235		Tangentially-fired	Wet Limestone
1236		Tangentially-fired	Wet Limestone
1237		Tangentially-fired	Wet Limestone
1238		Tangentially-fired	Wet Limestone
1239		Tangentially-fired	Wet Limestone
1240		Tangentially-fired	Wet Limestone
1241		Tangentially-fired	Wet Limestone
1242		Tangentially-fired	Wet Limestone
1243		Tangentially-fired	Wet Limestone
1244		Tangentially-fired	Wet Limestone
1245		Tangentially-fired	Wet Limestone
1246		Tangentially-fired	Wet Limestone
1247		Tangentially-fired	Wet Limestone

	S	T	U
1248		Tangentially-fired	Wet Limestone
1249		Tangentially-fired	Wet Limestone
1250		Tangentially-fired	Wet Limestone
1251		Tangentially-fired	Wet Limestone
1252		Tangentially-fired	Wet Limestone
1253		Tangentially-fired	Wet Limestone
1254		Tangentially-fired	Wet Limestone
1255		Tangentially-fired	Wet Limestone
1256		Tangentially-fired	Wet Limestone
1257		Tangentially-fired	Wet Limestone
1258		Tangentially-fired	Wet Limestone
1259		Tangentially-fired	Wet Limestone
1260		Tangentially-fired	Wet Limestone
1261		Tangentially-fired	Wet Limestone
1262		Tangentially-fired	Wet Limestone
1263		Tangentially-fired	Wet Limestone
1264		Tangentially-fired	Wet Limestone
1265		Tangentially-fired	Wet Limestone
1266		Tangentially-fired	Wet Limestone
1267		Tangentially-fired	Wet Limestone
1268		Tangentially-fired	Wet Limestone
1269		Tangentially-fired	Wet Limestone
1270		Tangentially-fired	Wet Limestone
1271		Tangentially-fired	Wet Limestone
1272		Tangentially-fired	Wet Limestone
1273		Tangentially-fired	Wet Limestone
1274		Tangentially-fired	Wet Limestone
1275		Tangentially-fired	Wet Limestone
1276		Tangentially-fired	Wet Limestone
1277		Tangentially-fired	Wet Limestone
1278		Tangentially-fired	Wet Limestone
1279		Tangentially-fired	Wet Limestone
1280		Tangentially-fired	Wet Limestone
1281		Tangentially-fired	Wet Limestone
1282		Tangentially-fired	Wet Limestone
1283		Tangentially-fired	Wet Limestone
1284		Tangentially-fired	Wet Limestone
1285		Tangentially-fired	Wet Limestone
1286		Tangentially-fired	Wet Limestone
1287		Tangentially-fired	Wet Limestone
1288		Tangentially-fired	Wet Limestone
1289		Tangentially-fired	Wet Limestone
1290		Tangentially-fired	Wet Limestone

	S	T	U
1291		Tangentially-fired	Wet Limestone
1292		Tangentially-fired	Wet Limestone
1293		Tangentially-fired	Wet Limestone
1294		Tangentially-fired	Wet Limestone
1295		Tangentially-fired	Wet Limestone
1296		Tangentially-fired	Wet Limestone
1297		Tangentially-fired	Wet Limestone
1298		Tangentially-fired	Wet Limestone
1299		Tangentially-fired	Wet Limestone
1300		Tangentially-fired	Wet Limestone
1301		Tangentially-fired	Wet Limestone
1302		Tangentially-fired	Wet Limestone
1303		Tangentially-fired	Wet Limestone
1304		Tangentially-fired	Wet Limestone
1305		Tangentially-fired	Wet Limestone
1306		Tangentially-fired	Wet Limestone
1307		Tangentially-fired	Wet Limestone
1308		Tangentially-fired	Wet Limestone
1309		Tangentially-fired	Wet Limestone
1310		Tangentially-fired	Wet Limestone
1311		Tangentially-fired	Wet Limestone
1312		Tangentially-fired	Wet Limestone
1313		Tangentially-fired	Wet Limestone
1314		Tangentially-fired	Wet Limestone
1315		Tangentially-fired	Wet Limestone
1316		Tangentially-fired	Wet Limestone
1317		Tangentially-fired	Wet Limestone
1318		Tangentially-fired	Wet Limestone
1319		Tangentially-fired	Wet Limestone
1320		Tangentially-fired	Wet Limestone
1321		Tangentially-fired	Wet Limestone
1322		Tangentially-fired	Wet Limestone
1323		Tangentially-fired	Wet Limestone
1324		Tangentially-fired	Wet Limestone
1325		Tangentially-fired	Wet Limestone
1326		Tangentially-fired	Wet Limestone
1327		Tangentially-fired	Wet Limestone
1328		Tangentially-fired	Wet Limestone
1329		Tangentially-fired	Wet Limestone
1330		Tangentially-fired	Wet Limestone
1331		Tangentially-fired	Wet Limestone
1332		Tangentially-fired	Wet Limestone
1333		Tangentially-fired	Wet Limestone

	S	T	U
1334		Tangentially-fired	Wet Limestone
1335		Tangentially-fired	Wet Limestone
1336		Tangentially-fired	Wet Limestone
1337		Tangentially-fired	Wet Limestone
1338		Tangentially-fired	Wet Limestone
1339		Tangentially-fired	Wet Limestone
1340		Tangentially-fired	Wet Limestone
1341		Tangentially-fired	Wet Limestone
1342		Tangentially-fired	Wet Limestone
1343		Tangentially-fired	Wet Limestone
1344		Tangentially-fired	Wet Limestone
1345		Tangentially-fired	Wet Limestone
1346		Tangentially-fired	Wet Limestone
1347		Tangentially-fired	Wet Limestone
1348		Tangentially-fired	Wet Limestone
1349		Tangentially-fired	Wet Limestone
1350		Tangentially-fired	Wet Limestone
1351		Tangentially-fired	Wet Limestone
1352		Tangentially-fired	Wet Limestone
1353		Tangentially-fired	Wet Limestone
1354		Tangentially-fired	Wet Limestone
1355		Tangentially-fired	Wet Limestone
1356		Tangentially-fired	Wet Limestone
1357		Tangentially-fired	Wet Limestone
1358		Tangentially-fired	Wet Limestone
1359		Tangentially-fired	Wet Limestone
1360		Tangentially-fired	Wet Limestone
1361		Tangentially-fired	Wet Limestone
1362		Tangentially-fired	Wet Limestone
1363		Tangentially-fired	Wet Limestone
1364		Tangentially-fired	Wet Limestone
1365		Tangentially-fired	Wet Limestone
1366		Tangentially-fired	Wet Limestone
1367		Tangentially-fired	Wet Limestone
1368		Tangentially-fired	Wet Limestone
1369		Tangentially-fired	Wet Limestone
1370		Tangentially-fired	Wet Limestone
1371		Tangentially-fired	Wet Limestone
1372		Tangentially-fired	Wet Limestone
1373		Tangentially-fired	Wet Limestone
1374		Tangentially-fired	Wet Limestone
1375		Tangentially-fired	Wet Limestone
1376		Tangentially-fired	Wet Limestone

	S	T	U
1377		Tangentially-fired	Wet Limestone
1378		Tangentially-fired	Wet Limestone
1379		Tangentially-fired	Wet Limestone
1380		Tangentially-fired	Wet Limestone
1381		Tangentially-fired	Wet Limestone
1382		Tangentially-fired	Wet Limestone
1383		Tangentially-fired	Wet Limestone
1384		Tangentially-fired	Wet Limestone
1385		Tangentially-fired	Wet Limestone
1386		Tangentially-fired	Wet Limestone
1387		Tangentially-fired	Wet Limestone
1388		Tangentially-fired	Wet Limestone
1389		Tangentially-fired	Wet Limestone
1390		Tangentially-fired	Wet Limestone
1391		Tangentially-fired	Wet Limestone
1392		Tangentially-fired	Wet Limestone
1393		Tangentially-fired	Wet Limestone
1394		Tangentially-fired	Wet Limestone
1395		Tangentially-fired	Wet Limestone
1396		Tangentially-fired	Wet Limestone
1397		Tangentially-fired	Wet Limestone
1398		Tangentially-fired	Wet Limestone
1399		Tangentially-fired	Wet Limestone
1400		Tangentially-fired	Wet Limestone
1401		Tangentially-fired	Wet Limestone
1402		Tangentially-fired	Wet Limestone
1403		Tangentially-fired	Wet Limestone
1404		Tangentially-fired	Wet Limestone
1405		Tangentially-fired	Wet Limestone
1406		Tangentially-fired	Wet Limestone
1407		Tangentially-fired	Wet Limestone
1408		Tangentially-fired	Wet Limestone
1409		Tangentially-fired	Wet Limestone
1410		Tangentially-fired	Wet Limestone
1411		Tangentially-fired	Wet Limestone
1412		Tangentially-fired	Wet Limestone
1413		Tangentially-fired	Wet Limestone
1414		Tangentially-fired	Wet Limestone
1415		Tangentially-fired	Wet Limestone
1416		Tangentially-fired	Wet Limestone
1417		Tangentially-fired	Wet Limestone
1418		Tangentially-fired	Wet Limestone
1419		Tangentially-fired	Wet Limestone

	S	T	U
1420		Tangentially-fired	Wet Limestone
1421		Tangentially-fired	Wet Limestone
1422		Tangentially-fired	Wet Limestone
1423		Tangentially-fired	Wet Limestone
1424		Tangentially-fired	Wet Limestone
1425		Tangentially-fired	Wet Limestone
1426		Tangentially-fired	Wet Limestone
1427		Tangentially-fired	Wet Limestone
1428		Tangentially-fired	Wet Limestone
1429		Tangentially-fired	Wet Limestone
1430		Tangentially-fired	Wet Limestone
1431		Tangentially-fired	Wet Limestone
1432		Tangentially-fired	Wet Limestone
1433		Tangentially-fired	Wet Limestone
1434		Tangentially-fired	Wet Limestone
1435		Tangentially-fired	Wet Limestone
1436		Tangentially-fired	Wet Limestone
1437		Tangentially-fired	Wet Limestone
1438		Tangentially-fired	Wet Limestone
1439		Tangentially-fired	Wet Limestone
1440		Tangentially-fired	Wet Limestone
1441		Tangentially-fired	Wet Limestone
1442		Tangentially-fired	Wet Limestone
1443		Tangentially-fired	Wet Limestone
1444		Tangentially-fired	Wet Limestone
1445		Tangentially-fired	Wet Limestone
1446		Tangentially-fired	Wet Limestone
1447		Tangentially-fired	Wet Limestone
1448		Tangentially-fired	Wet Limestone
1449		Tangentially-fired	Wet Limestone
1450		Tangentially-fired	Wet Limestone
1451		Tangentially-fired	Wet Limestone
1452		Tangentially-fired	Wet Limestone
1453		Tangentially-fired	Wet Limestone
1454		Tangentially-fired	Wet Limestone
1455		Tangentially-fired	Wet Limestone
1456		Tangentially-fired	Wet Limestone
1457		Tangentially-fired	Wet Limestone
1458		Tangentially-fired	Wet Limestone
1459		Tangentially-fired	Wet Limestone
1460		Tangentially-fired	Wet Limestone
1461		Tangentially-fired	Wet Limestone
1462		Tangentially-fired	Wet Limestone

	S	T	U
1463		Tangentially-fired	Wet Limestone
1464		Tangentially-fired	Wet Limestone
1465		Tangentially-fired	Wet Limestone
1466		Tangentially-fired	Wet Limestone
1467		Tangentially-fired	Wet Limestone
1468		Tangentially-fired	Wet Limestone
1469		Tangentially-fired	Wet Limestone
1470		Tangentially-fired	Wet Limestone
1471		Tangentially-fired	Wet Limestone
1472		Tangentially-fired	Wet Limestone
1473		Tangentially-fired	Wet Limestone
1474		Tangentially-fired	Wet Limestone
1475		Tangentially-fired	Wet Limestone
1476		Tangentially-fired	Wet Limestone
1477		Tangentially-fired	Wet Limestone
1478		Tangentially-fired	Wet Limestone
1479		Tangentially-fired	Wet Limestone
1480		Tangentially-fired	Wet Limestone
1481		Tangentially-fired	Wet Limestone
1482		Tangentially-fired	Wet Limestone
1483		Tangentially-fired	Wet Limestone
1484		Tangentially-fired	Wet Limestone
1485		Tangentially-fired	Wet Limestone
1486		Tangentially-fired	Wet Limestone
1487		Tangentially-fired	Wet Limestone
1488		Tangentially-fired	Wet Limestone
1489		Tangentially-fired	Wet Limestone
1490		Tangentially-fired	Wet Limestone
1491		Tangentially-fired	Wet Limestone
1492		Tangentially-fired	Wet Limestone
1493		Tangentially-fired	Wet Limestone
1494		Tangentially-fired	Wet Limestone
1495		Tangentially-fired	Wet Limestone
1496		Tangentially-fired	Wet Limestone
1497		Tangentially-fired	Wet Limestone
1498		Tangentially-fired	Wet Limestone
1499		Tangentially-fired	Wet Limestone
1500		Tangentially-fired	Wet Limestone
1501		Tangentially-fired	Wet Limestone
1502		Tangentially-fired	Wet Limestone
1503		Tangentially-fired	Wet Limestone
1504		Tangentially-fired	Wet Limestone
1505		Tangentially-fired	Wet Limestone

	S	T	U
1506		Tangentially-fired	Wet Limestone
1507		Tangentially-fired	Wet Limestone
1508		Tangentially-fired	Wet Limestone
1509		Tangentially-fired	Wet Limestone
1510		Tangentially-fired	Wet Limestone
1511		Tangentially-fired	Wet Limestone
1512		Tangentially-fired	Wet Limestone
1513		Tangentially-fired	Wet Limestone
1514		Tangentially-fired	Wet Limestone
1515		Tangentially-fired	Wet Limestone
1516		Tangentially-fired	Wet Limestone
1517		Tangentially-fired	Wet Limestone
1518		Tangentially-fired	Wet Limestone
1519		Tangentially-fired	Wet Limestone
1520		Tangentially-fired	Wet Limestone
1521		Tangentially-fired	Wet Limestone
1522		Tangentially-fired	Wet Limestone
1523		Tangentially-fired	Wet Limestone
1524		Tangentially-fired	Wet Limestone
1525		Tangentially-fired	Wet Limestone
1526		Tangentially-fired	Wet Limestone
1527		Tangentially-fired	Wet Limestone
1528		Tangentially-fired	Wet Limestone
1529		Tangentially-fired	Wet Limestone
1530		Tangentially-fired	Wet Limestone
1531		Tangentially-fired	Wet Limestone
1532		Tangentially-fired	Wet Limestone
1533		Tangentially-fired	Wet Limestone
1534		Tangentially-fired	Wet Limestone
1535		Tangentially-fired	Wet Limestone
1536		Tangentially-fired	Wet Limestone
1537		Tangentially-fired	Wet Limestone
1538		Tangentially-fired	Wet Limestone
1539		Tangentially-fired	Wet Limestone
1540		Tangentially-fired	Wet Limestone
1541		Tangentially-fired	Wet Limestone
1542		Tangentially-fired	Wet Limestone
1543		Tangentially-fired	Wet Limestone
1544		Tangentially-fired	Wet Limestone
1545		Tangentially-fired	Wet Limestone
1546		Tangentially-fired	Wet Limestone
1547		Tangentially-fired	Wet Limestone
1548		Tangentially-fired	Wet Limestone

	S	T	U
1549		Tangentially-fired	Wet Limestone
1550		Tangentially-fired	Wet Limestone
1551		Tangentially-fired	Wet Limestone
1552		Tangentially-fired	Wet Limestone
1553		Tangentially-fired	Wet Limestone
1554		Tangentially-fired	Wet Limestone
1555		Tangentially-fired	Wet Limestone
1556		Tangentially-fired	Wet Limestone
1557		Tangentially-fired	Wet Limestone
1558		Tangentially-fired	Wet Limestone
1559		Tangentially-fired	Wet Limestone
1560		Tangentially-fired	Wet Limestone
1561		Tangentially-fired	Wet Limestone
1562		Tangentially-fired	Wet Limestone
1563		Tangentially-fired	Wet Limestone
1564		Tangentially-fired	Wet Limestone
1565		Tangentially-fired	Wet Limestone
1566		Tangentially-fired	Wet Limestone
1567		Tangentially-fired	Wet Limestone
1568		Tangentially-fired	Wet Limestone
1569		Tangentially-fired	Wet Limestone
1570		Tangentially-fired	Wet Limestone
1571		Tangentially-fired	Wet Limestone
1572		Tangentially-fired	Wet Limestone
1573		Tangentially-fired	Wet Limestone
1574		Tangentially-fired	Wet Limestone
1575		Tangentially-fired	Wet Limestone
1576		Tangentially-fired	Wet Limestone
1577		Tangentially-fired	Wet Limestone
1578		Tangentially-fired	Wet Limestone
1579		Tangentially-fired	Wet Limestone
1580		Tangentially-fired	Wet Limestone
1581		Tangentially-fired	Wet Limestone
1582		Tangentially-fired	Wet Limestone
1583		Tangentially-fired	Wet Limestone
1584		Tangentially-fired	Wet Limestone
1585		Tangentially-fired	Wet Limestone
1586		Tangentially-fired	Wet Limestone
1587		Tangentially-fired	Wet Limestone
1588		Tangentially-fired	Wet Limestone
1589		Tangentially-fired	Wet Limestone
1590		Tangentially-fired	Wet Limestone
1591		Tangentially-fired	Wet Limestone

	S	T	U
1592		Tangentially-fired	Wet Limestone
1593		Tangentially-fired	Wet Limestone
1594		Tangentially-fired	Wet Limestone
1595		Tangentially-fired	Wet Limestone
1596		Tangentially-fired	Wet Limestone
1597		Tangentially-fired	Wet Limestone
1598		Tangentially-fired	Wet Limestone
1599		Tangentially-fired	Wet Limestone
1600		Tangentially-fired	Wet Limestone
1601		Tangentially-fired	Wet Limestone
1602		Tangentially-fired	Wet Limestone
1603		Tangentially-fired	Wet Limestone
1604		Tangentially-fired	Wet Limestone
1605		Tangentially-fired	Wet Limestone
1606		Tangentially-fired	Wet Limestone
1607		Tangentially-fired	Wet Limestone
1608		Tangentially-fired	Wet Limestone
1609		Tangentially-fired	Wet Limestone
1610		Tangentially-fired	Wet Limestone
1611		Tangentially-fired	Wet Limestone
1612		Tangentially-fired	Wet Limestone
1613		Tangentially-fired	Wet Limestone
1614		Tangentially-fired	Wet Limestone
1615		Tangentially-fired	Wet Limestone
1616		Tangentially-fired	Wet Limestone
1617		Tangentially-fired	Wet Limestone
1618		Tangentially-fired	Wet Limestone
1619		Tangentially-fired	Wet Limestone
1620		Tangentially-fired	Wet Limestone
1621		Tangentially-fired	Wet Limestone
1622		Tangentially-fired	Wet Limestone
1623		Tangentially-fired	Wet Limestone
1624		Tangentially-fired	Wet Limestone
1625		Tangentially-fired	Wet Limestone
1626		Tangentially-fired	Wet Limestone
1627		Tangentially-fired	Wet Limestone
1628		Tangentially-fired	Wet Limestone
1629		Tangentially-fired	Wet Limestone
1630		Tangentially-fired	Wet Limestone
1631		Tangentially-fired	Wet Limestone
1632		Tangentially-fired	Wet Limestone
1633		Tangentially-fired	Wet Limestone
1634		Tangentially-fired	Wet Limestone

	S	T	U
1635		Tangentially-fired	Wet Limestone
1636		Tangentially-fired	Wet Limestone
1637		Tangentially-fired	Wet Limestone
1638		Tangentially-fired	Wet Limestone
1639		Tangentially-fired	Wet Limestone
1640		Tangentially-fired	Wet Limestone
1641		Tangentially-fired	Wet Limestone
1642		Tangentially-fired	Wet Limestone
1643		Tangentially-fired	Wet Limestone
1644		Tangentially-fired	Wet Limestone
1645		Tangentially-fired	Wet Limestone
1646		Tangentially-fired	Wet Limestone
1647		Tangentially-fired	Wet Limestone
1648		Tangentially-fired	Wet Limestone
1649		Tangentially-fired	Wet Limestone
1650		Tangentially-fired	Wet Limestone
1651		Tangentially-fired	Wet Limestone
1652		Tangentially-fired	Wet Limestone
1653		Tangentially-fired	Wet Limestone
1654		Tangentially-fired	Wet Limestone
1655		Tangentially-fired	Wet Limestone
1656		Tangentially-fired	Wet Limestone
1657		Tangentially-fired	Wet Limestone
1658		Tangentially-fired	Wet Limestone
1659		Tangentially-fired	Wet Limestone
1660		Tangentially-fired	Wet Limestone
1661		Tangentially-fired	Wet Limestone
1662		Tangentially-fired	Wet Limestone
1663		Tangentially-fired	Wet Limestone
1664		Tangentially-fired	Wet Limestone
1665		Tangentially-fired	Wet Limestone
1666		Tangentially-fired	Wet Limestone
1667		Tangentially-fired	Wet Limestone
1668		Tangentially-fired	Wet Limestone
1669		Tangentially-fired	Wet Limestone
1670		Tangentially-fired	Wet Limestone
1671		Tangentially-fired	Wet Limestone
1672		Tangentially-fired	Wet Limestone
1673		Tangentially-fired	Wet Limestone
1674		Tangentially-fired	Wet Limestone
1675		Tangentially-fired	Wet Limestone
1676		Tangentially-fired	Wet Limestone
1677		Tangentially-fired	Wet Limestone

	S	T	U
1678		Tangentially-fired	Wet Limestone
1679		Tangentially-fired	Wet Limestone
1680		Tangentially-fired	Wet Limestone
1681		Tangentially-fired	Wet Limestone
1682		Tangentially-fired	Wet Limestone
1683		Tangentially-fired	Wet Limestone
1684		Tangentially-fired	Wet Limestone
1685		Tangentially-fired	Wet Limestone
1686		Tangentially-fired	Wet Limestone
1687		Tangentially-fired	Wet Limestone
1688		Tangentially-fired	Wet Limestone
1689		Tangentially-fired	Wet Limestone
1690		Tangentially-fired	Wet Limestone
1691		Tangentially-fired	Wet Limestone
1692		Tangentially-fired	Wet Limestone
1693		Tangentially-fired	Wet Limestone
1694		Tangentially-fired	Wet Limestone
1695		Tangentially-fired	Wet Limestone
1696		Tangentially-fired	Wet Limestone
1697		Tangentially-fired	Wet Limestone
1698		Tangentially-fired	Wet Limestone
1699		Tangentially-fired	Wet Limestone
1700		Tangentially-fired	Wet Limestone
1701		Tangentially-fired	Wet Limestone
1702		Tangentially-fired	Wet Limestone
1703		Tangentially-fired	Wet Limestone
1704		Tangentially-fired	Wet Limestone
1705		Tangentially-fired	Wet Limestone
1706		Tangentially-fired	Wet Limestone
1707		Tangentially-fired	Wet Limestone
1708		Tangentially-fired	Wet Limestone
1709		Tangentially-fired	Wet Limestone
1710		Tangentially-fired	Wet Limestone
1711		Tangentially-fired	Wet Limestone
1712		Tangentially-fired	Wet Limestone
1713		Tangentially-fired	Wet Limestone
1714		Tangentially-fired	Wet Limestone
1715		Tangentially-fired	Wet Limestone
1716		Tangentially-fired	Wet Limestone
1717		Tangentially-fired	Wet Limestone
1718		Tangentially-fired	Wet Limestone
1719		Tangentially-fired	Wet Limestone
1720		Tangentially-fired	Wet Limestone

	S	T	U
1721		Tangentially-fired	Wet Limestone
1722		Tangentially-fired	Wet Limestone
1723		Tangentially-fired	Wet Limestone
1724		Tangentially-fired	Wet Limestone
1725		Tangentially-fired	Wet Limestone
1726		Tangentially-fired	Wet Limestone
1727		Tangentially-fired	Wet Limestone
1728		Tangentially-fired	Wet Limestone
1729		Tangentially-fired	Wet Limestone
1730		Tangentially-fired	Wet Limestone
1731		Tangentially-fired	Wet Limestone
1732		Tangentially-fired	Wet Limestone
1733		Tangentially-fired	Wet Limestone
1734		Tangentially-fired	Wet Limestone
1735		Tangentially-fired	Wet Limestone
1736		Tangentially-fired	Wet Limestone
1737		Tangentially-fired	Wet Limestone
1738		Tangentially-fired	Wet Limestone
1739		Tangentially-fired	Wet Limestone
1740		Tangentially-fired	Wet Limestone
1741		Tangentially-fired	Wet Limestone
1742		Tangentially-fired	Wet Limestone
1743		Tangentially-fired	Wet Limestone
1744		Tangentially-fired	Wet Limestone
1745		Tangentially-fired	Wet Limestone
1746		Tangentially-fired	Wet Limestone
1747		Tangentially-fired	Wet Limestone
1748		Tangentially-fired	Wet Limestone
1749		Tangentially-fired	Wet Limestone
1750		Tangentially-fired	Wet Limestone
1751		Tangentially-fired	Wet Limestone
1752		Tangentially-fired	Wet Limestone
1753		Tangentially-fired	Wet Limestone
1754		Tangentially-fired	Wet Limestone
1755		Tangentially-fired	Wet Limestone
1756		Tangentially-fired	Wet Limestone
1757		Tangentially-fired	Wet Limestone
1758		Tangentially-fired	Wet Limestone
1759		Tangentially-fired	Wet Limestone
1760		Tangentially-fired	Wet Limestone
1761		Tangentially-fired	Wet Limestone
1762		Tangentially-fired	Wet Limestone
1763		Tangentially-fired	Wet Limestone

	S	T	U
1764		Tangentially-fired	Wet Limestone
1765		Tangentially-fired	Wet Limestone
1766		Tangentially-fired	Wet Limestone
1767		Tangentially-fired	Wet Limestone
1768		Tangentially-fired	Wet Limestone
1769		Tangentially-fired	Wet Limestone
1770		Tangentially-fired	Wet Limestone
1771		Tangentially-fired	Wet Limestone
1772		Tangentially-fired	Wet Limestone
1773		Tangentially-fired	Wet Limestone
1774		Tangentially-fired	Wet Limestone
1775		Tangentially-fired	Wet Limestone
1776		Tangentially-fired	Wet Limestone
1777		Tangentially-fired	Wet Limestone
1778		Tangentially-fired	Wet Limestone
1779		Tangentially-fired	Wet Limestone
1780		Tangentially-fired	Wet Limestone
1781		Tangentially-fired	Wet Limestone
1782		Tangentially-fired	Wet Limestone
1783		Tangentially-fired	Wet Limestone
1784		Tangentially-fired	Wet Limestone
1785		Tangentially-fired	Wet Limestone
1786		Tangentially-fired	Wet Limestone
1787		Tangentially-fired	Wet Limestone
1788		Tangentially-fired	Wet Limestone
1789		Tangentially-fired	Wet Limestone
1790		Tangentially-fired	Wet Limestone
1791		Tangentially-fired	Wet Limestone
1792		Tangentially-fired	Wet Limestone
1793		Tangentially-fired	Wet Limestone
1794		Tangentially-fired	Wet Limestone
1795		Tangentially-fired	Wet Limestone
1796		Tangentially-fired	Wet Limestone
1797		Tangentially-fired	Wet Limestone
1798		Tangentially-fired	Wet Limestone
1799		Tangentially-fired	Wet Limestone
1800		Tangentially-fired	Wet Limestone
1801		Tangentially-fired	Wet Limestone
1802		Tangentially-fired	Wet Limestone
1803		Tangentially-fired	Wet Limestone
1804		Tangentially-fired	Wet Limestone
1805		Tangentially-fired	Wet Limestone
1806		Tangentially-fired	Wet Limestone

	S	T	U
1807		Tangentially-fired	Wet Limestone
1808		Tangentially-fired	Wet Limestone
1809		Tangentially-fired	Wet Limestone
1810		Tangentially-fired	Wet Limestone
1811		Tangentially-fired	Wet Limestone
1812		Tangentially-fired	Wet Limestone
1813		Tangentially-fired	Wet Limestone
1814		Tangentially-fired	Wet Limestone
1815		Tangentially-fired	Wet Limestone
1816		Tangentially-fired	Wet Limestone
1817		Tangentially-fired	Wet Limestone
1818		Tangentially-fired	Wet Limestone
1819		Tangentially-fired	Wet Limestone
1820		Tangentially-fired	Wet Limestone
1821		Tangentially-fired	Wet Limestone
1822		Tangentially-fired	Wet Limestone
1823		Tangentially-fired	Wet Limestone
1824		Tangentially-fired	Wet Limestone
1825		Tangentially-fired	Wet Limestone
1826		Tangentially-fired	Wet Limestone
1827		Tangentially-fired	Wet Limestone
1828		Tangentially-fired	Wet Limestone
1829		Tangentially-fired	Wet Limestone
1830		Tangentially-fired	Wet Limestone
1831		Tangentially-fired	Wet Limestone
1832		Tangentially-fired	Wet Limestone
1833		Tangentially-fired	Wet Limestone
1834		Tangentially-fired	Wet Limestone
1835		Tangentially-fired	Wet Limestone
1836		Tangentially-fired	Wet Limestone
1837		Tangentially-fired	Wet Limestone
1838		Tangentially-fired	Wet Limestone
1839		Tangentially-fired	Wet Limestone
1840		Tangentially-fired	Wet Limestone
1841		Tangentially-fired	Wet Limestone
1842		Tangentially-fired	Wet Limestone
1843		Tangentially-fired	Wet Limestone
1844		Tangentially-fired	Wet Limestone
1845		Tangentially-fired	Wet Limestone
1846		Tangentially-fired	Wet Limestone
1847		Tangentially-fired	Wet Limestone
1848		Tangentially-fired	Wet Limestone
1849		Tangentially-fired	Wet Limestone

	S	T	U
1850		Tangentially-fired	Wet Limestone
1851		Tangentially-fired	Wet Limestone
1852		Tangentially-fired	Wet Limestone
1853		Tangentially-fired	Wet Limestone
1854		Tangentially-fired	Wet Limestone
1855		Tangentially-fired	Wet Limestone
1856		Tangentially-fired	Wet Limestone
1857		Tangentially-fired	Wet Limestone
1858		Tangentially-fired	Wet Limestone
1859		Tangentially-fired	Wet Limestone
1860		Tangentially-fired	Wet Limestone
1861		Tangentially-fired	Wet Limestone
1862		Tangentially-fired	Wet Limestone
1863		Tangentially-fired	Wet Limestone
1864		Tangentially-fired	Wet Limestone
1865		Tangentially-fired	Wet Limestone
1866		Tangentially-fired	Wet Limestone
1867		Tangentially-fired	Wet Limestone
1868		Tangentially-fired	Wet Limestone
1869		Tangentially-fired	Wet Limestone
1870		Tangentially-fired	Wet Limestone
1871		Tangentially-fired	Wet Limestone
1872		Tangentially-fired	Wet Limestone
1873		Tangentially-fired	Wet Limestone
1874		Tangentially-fired	Wet Limestone
1875		Tangentially-fired	Wet Limestone
1876		Tangentially-fired	Wet Limestone
1877		Tangentially-fired	Wet Limestone
1878		Tangentially-fired	Wet Limestone
1879		Tangentially-fired	Wet Limestone
1880		Tangentially-fired	Wet Limestone
1881		Tangentially-fired	Wet Limestone
1882		Tangentially-fired	Wet Limestone
1883		Tangentially-fired	Wet Limestone
1884		Tangentially-fired	Wet Limestone
1885		Tangentially-fired	Wet Limestone
1886		Tangentially-fired	Wet Limestone
1887		Tangentially-fired	Wet Limestone
1888		Tangentially-fired	Wet Limestone
1889		Tangentially-fired	Wet Limestone
1890		Tangentially-fired	Wet Limestone
1891		Tangentially-fired	Wet Limestone
1892		Tangentially-fired	Wet Limestone

	S	T	U
1893		Tangentially-fired	Wet Limestone
1894		Tangentially-fired	Wet Limestone
1895		Tangentially-fired	Wet Limestone
1896		Tangentially-fired	Wet Limestone
1897		Tangentially-fired	Wet Limestone
1898		Tangentially-fired	Wet Limestone
1899		Tangentially-fired	Wet Limestone
1900		Tangentially-fired	Wet Limestone
1901		Tangentially-fired	Wet Limestone
1902		Tangentially-fired	Wet Limestone
1903		Tangentially-fired	Wet Limestone
1904		Tangentially-fired	Wet Limestone
1905		Tangentially-fired	Wet Limestone
1906		Tangentially-fired	Wet Limestone
1907		Tangentially-fired	Wet Limestone
1908		Tangentially-fired	Wet Limestone
1909		Tangentially-fired	Wet Limestone
1910		Tangentially-fired	Wet Limestone
1911		Tangentially-fired	Wet Limestone
1912		Tangentially-fired	Wet Limestone
1913		Tangentially-fired	Wet Limestone
1914		Tangentially-fired	Wet Limestone
1915		Tangentially-fired	Wet Limestone
1916		Tangentially-fired	Wet Limestone
1917		Tangentially-fired	Wet Limestone

	V
1	NOx Controls
2	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
3	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
4	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
5	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
6	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
7	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
8	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
9	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
10	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
11	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
12	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
13	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
14	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
15	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
16	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
17	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
18	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
19	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
20	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
21	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
22	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
23	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
24	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
25	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
26	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
27	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
28	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
29	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
30	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
31	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
32	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
33	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
34	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
35	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
36	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
37	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
38	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
39	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
40	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
41	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
42	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
43	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
44	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
45	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
46	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
47	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
48	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
49	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
50	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
51	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
52	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
53	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
54	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
55	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
56	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
57	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
58	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
59	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
60	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
61	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
62	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
63	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
64	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
65	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
66	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
67	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
68	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
69	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
70	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
71	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
72	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
73	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
74	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
75	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
76	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
77	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
78	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
79	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
80	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
81	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
82	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
83	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
84	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
85	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
86	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
87	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
88	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
89	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
90	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
91	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
92	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
93	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
94	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
95	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
96	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
97	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
98	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
99	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
100	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
101	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
102	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
103	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
104	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
105	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
106	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
107	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
108	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
109	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
110	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
111	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
112	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
113	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
114	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
115	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
116	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
117	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
118	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
119	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
120	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
121	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
122	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
123	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
124	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
125	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
126	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
127	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
128	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
129	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
130	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
131	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
132	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
133	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
134	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
135	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
136	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
137	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
138	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
139	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
140	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
141	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
142	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
143	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
144	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
145	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
146	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
147	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
148	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
149	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
150	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
151	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
152	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
153	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
154	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
155	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
156	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
157	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
158	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
159	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
160	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
161	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
162	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
163	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
164	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
165	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
166	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
167	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
168	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
169	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
170	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
171	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
172	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
173	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
174	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
175	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
176	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
177	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
178	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
179	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
180	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
181	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
182	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
183	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
184	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
185	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
186	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
187	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
188	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
189	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
190	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
191	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
192	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
193	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
194	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
195	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
196	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
197	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
198	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
199	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
200	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
201	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
202	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
203	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
204	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
205	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
206	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
207	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
208	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
209	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
210	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
211	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
212	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
213	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
214	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
215	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
216	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
217	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
218	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
219	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
220	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
221	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
222	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
223	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
224	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
225	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
226	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
227	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
228	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
229	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
230	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
231	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
232	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
233	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
234	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
235	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
236	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
237	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
238	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
239	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
240	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
241	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
242	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
243	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
244	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
245	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
246	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
247	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
248	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
249	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
250	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
251	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
252	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
253	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
254	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
255	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
256	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
257	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
258	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
259	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
260	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
261	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
262	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
263	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
264	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
265	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
266	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
267	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
268	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
269	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
270	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
271	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
272	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
273	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
274	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
275	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
276	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
277	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
278	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
279	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
280	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
281	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
282	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
283	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
284	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
285	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
286	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
287	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
288	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
289	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
290	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
291	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
292	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
293	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
294	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
295	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
296	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
297	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
298	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
299	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
300	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
301	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
302	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
303	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
304	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
305	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
306	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
307	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
308	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
309	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
310	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
311	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
312	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
313	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
314	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
315	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
316	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
317	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
318	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
319	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
320	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
321	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
322	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
323	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
324	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
325	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
326	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
327	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
328	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
329	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
330	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
331	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
332	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
333	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
334	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
335	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
336	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
337	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
338	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
339	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
340	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
341	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
342	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
343	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
344	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
345	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
346	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
347	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
348	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
349	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
350	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
351	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
352	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
353	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
354	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
355	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
356	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
357	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
358	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
359	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
360	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
361	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
362	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
363	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
364	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
365	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
366	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
367	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
368	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
369	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
370	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
371	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
372	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
373	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
374	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
375	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
376	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
377	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
378	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
379	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
380	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
381	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
382	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
383	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
384	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
385	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
386	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
387	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
388	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
389	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
390	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
391	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
392	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
393	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
394	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
395	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
396	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
397	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
398	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
399	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
400	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
401	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
402	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
403	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
404	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
405	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
406	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
407	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
408	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
409	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
410	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
411	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
412	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
413	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
414	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
415	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
416	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
417	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
418	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
419	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
420	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
421	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
422	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
423	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
424	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
425	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
426	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
427	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
428	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
429	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
430	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
431	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
432	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
433	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
434	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
435	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
436	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
437	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
438	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
439	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
440	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
441	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
442	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
443	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
444	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
445	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
446	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
447	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
448	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
449	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
450	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
451	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
452	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
453	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
454	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
455	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
456	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
457	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
458	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
459	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
460	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
461	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
462	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
463	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
464	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
465	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
466	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
467	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
468	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
469	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
470	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
471	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
472	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
473	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
474	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
475	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
476	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
477	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
478	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
479	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
480	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
481	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
482	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
483	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
484	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
485	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
486	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
487	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
488	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
489	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
490	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
491	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
492	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
493	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
494	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
495	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
496	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
497	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
498	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
499	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
500	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
501	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
502	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
503	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
504	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
505	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
506	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
507	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
508	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
509	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
510	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
511	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
512	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
513	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
514	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
515	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
516	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
517	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
518	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
519	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
520	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
521	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
522	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
523	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
524	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
525	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
526	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
527	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
528	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
529	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
530	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
531	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
532	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
533	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
534	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
535	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
536	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
537	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
538	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
539	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
540	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
541	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
542	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
543	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
544	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
545	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
546	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
547	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
548	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
549	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
550	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
551	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
552	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
553	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
554	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
555	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
556	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
557	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
558	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
559	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
560	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
561	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
562	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
563	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
564	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
565	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
566	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
567	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
568	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
569	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
570	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
571	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
572	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
573	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
574	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
575	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
576	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
577	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
578	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
579	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
580	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
581	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
582	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
583	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
584	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
585	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
586	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
587	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
588	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
589	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
590	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
591	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
592	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
593	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
594	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
595	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
596	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
597	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
598	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
599	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
600	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
601	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
602	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
603	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
604	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
605	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
606	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
607	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
608	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
609	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
610	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
611	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
612	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
613	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
614	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
615	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
616	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
617	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
618	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
619	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
620	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
621	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
622	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
623	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
624	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
625	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
626	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
627	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
628	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
629	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
630	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
631	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
632	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
633	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
634	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
635	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
636	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
637	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
638	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
639	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
640	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
641	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
642	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
643	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
644	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
645	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
646	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
647	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
648	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
649	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
650	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
651	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
652	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
653	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
654	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
655	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
656	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
657	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
658	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
659	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
660	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
661	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
662	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
663	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
664	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
665	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
666	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
667	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
668	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
669	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
670	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
671	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
672	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
673	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
674	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
675	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
676	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
677	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
678	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
679	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
680	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
681	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
682	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
683	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
684	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
685	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
686	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
687	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
688	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
689	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
690	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
691	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
692	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
693	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
694	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
695	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
696	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
697	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
698	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
699	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
700	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
701	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
702	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
703	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
704	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
705	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
706	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
707	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
708	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
709	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
710	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
711	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
712	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
713	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
714	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
715	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
716	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
717	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
718	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
719	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
720	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
721	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
722	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
723	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
724	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
725	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
726	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
727	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
728	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
729	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
730	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
731	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
732	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
733	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
734	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
735	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
736	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
737	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
738	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
739	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
740	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
741	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
742	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
743	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
744	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
745	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
746	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
747	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
748	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
749	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
750	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
751	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
752	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
753	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
754	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
755	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
756	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
757	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
758	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
759	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
760	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
761	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
762	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
763	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
764	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
765	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
766	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
767	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
768	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
769	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
770	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
771	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
772	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
773	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
774	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
775	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
776	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
777	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
778	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
779	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
780	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
781	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
782	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
783	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
784	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
785	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
786	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
787	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
788	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
789	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
790	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
791	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
792	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
793	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
794	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
795	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
796	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
797	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
798	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
799	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
800	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
801	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
802	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
803	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
804	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
805	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
806	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
807	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
808	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
809	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
810	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
811	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
812	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
813	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
814	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
815	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
816	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
817	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
818	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
819	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
820	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
821	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
822	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
823	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
824	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
825	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
826	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
827	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
828	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
829	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
830	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
831	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
832	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
833	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
834	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
835	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
836	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
837	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
838	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
839	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
840	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
841	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
842	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
843	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
844	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
845	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
846	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
847	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
848	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
849	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
850	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
851	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
852	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
853	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
854	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
855	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
856	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
857	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
858	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
859	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
860	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
861	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
862	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
863	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
864	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
865	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
866	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
867	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
868	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
869	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
870	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
871	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
872	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
873	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
874	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
875	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
876	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
877	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
878	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
879	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
880	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
881	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
882	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
883	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
884	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
885	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
886	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
887	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
888	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
889	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
890	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
891	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
892	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
893	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
894	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
895	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
896	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
897	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
898	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
899	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
900	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
901	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
902	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
903	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
904	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
905	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
906	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
907	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
908	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
909	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
910	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
911	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
912	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
913	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
914	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
915	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
916	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
917	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
918	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
919	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
920	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
921	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
922	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
923	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
924	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
925	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
926	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
927	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
928	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
929	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
930	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
931	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
932	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
933	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
934	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
935	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
936	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
937	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
938	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
939	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
940	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
941	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
942	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
943	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
944	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
945	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
946	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
947	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
948	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
949	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
950	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
951	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
952	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
953	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
954	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
955	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
956	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
957	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
958	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
959	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
960	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
961	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
962	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
963	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
964	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
965	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
966	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
967	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
968	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
969	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
970	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
971	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
972	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
973	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
974	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
975	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
976	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
977	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
978	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
979	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
980	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
981	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
982	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
983	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
984	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
985	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
986	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
987	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
988	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
989	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
990	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
991	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
992	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
993	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
994	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
995	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
996	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
997	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
998	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
999	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1000	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1001	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1002	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1003	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1004	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1005	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1006	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1007	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1008	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1009	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1010	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1011	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1012	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1013	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1014	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1015	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1016	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1017	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1018	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1019	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1020	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1021	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1022	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1023	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1024	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1025	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1026	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1027	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1028	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1029	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1030	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1031	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1032	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1033	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1034	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1035	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1036	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1037	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1038	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1039	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1040	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1041	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1042	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1043	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1044	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1045	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1046	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1047	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1048	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1049	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1050	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1051	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1052	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1053	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1054	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1055	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1056	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1057	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1058	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1059	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1060	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1061	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1062	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1063	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1064	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1065	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1066	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1067	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1068	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1069	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1070	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1071	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1072	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1073	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1074	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1075	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1076	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1077	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1078	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1079	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1080	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1081	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1082	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1083	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1084	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1085	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1086	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1087	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1088	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1089	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1090	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1091	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1092	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1093	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1094	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1095	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1096	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1097	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1098	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1099	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1100	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1101	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1102	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1103	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1104	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1105	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1106	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1107	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1108	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1109	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1110	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1111	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1112	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1113	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1114	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1115	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1116	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1117	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1118	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1119	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1120	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1121	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1122	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1123	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1124	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1125	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1126	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1127	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1128	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1129	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1130	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1131	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1132	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1133	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1134	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1135	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1136	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1137	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1138	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1139	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1140	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1141	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1142	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1143	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1144	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1145	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1146	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1147	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1148	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1149	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1150	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1151	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1152	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1153	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1154	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1155	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1156	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1157	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1158	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1159	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1160	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1161	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1162	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1163	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1164	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1165	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1166	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1167	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1168	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1169	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1170	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1171	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1172	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1173	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1174	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1175	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1176	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1177	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1178	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1179	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1180	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1181	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1182	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1183	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1184	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1185	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1186	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1187	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1188	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1189	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1190	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1191	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1192	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1193	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1194	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1195	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1196	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1197	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1198	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1199	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1200	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1201	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1202	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1203	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1204	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1205	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1206	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1207	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1208	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1209	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1210	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1211	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1212	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1213	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1214	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1215	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1216	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1217	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1218	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1219	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1220	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1221	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1222	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1223	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1224	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1225	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1226	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1227	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1228	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1229	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1230	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1231	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1232	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1233	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1234	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1235	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1236	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1237	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1238	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1239	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1240	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1241	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1242	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1243	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1244	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1245	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1246	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1247	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1248	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1249	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1250	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1251	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1252	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1253	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1254	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1255	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1256	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1257	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1258	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1259	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1260	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1261	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1262	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1263	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1264	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1265	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1266	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1267	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1268	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1269	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1270	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1271	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1272	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1273	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1274	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1275	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1276	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1277	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1278	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1279	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1280	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1281	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1282	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1283	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1284	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1285	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1286	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1287	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1288	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1289	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1290	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1291	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1292	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1293	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1294	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1295	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1296	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1297	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1298	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1299	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1300	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1301	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1302	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1303	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1304	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1305	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1306	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1307	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1308	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1309	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1310	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1311	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1312	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1313	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1314	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1315	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1316	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1317	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1318	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1319	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1320	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1321	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1322	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1323	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1324	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1325	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1326	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1327	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1328	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1329	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1330	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1331	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1332	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1333	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1334	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1335	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1336	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1337	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1338	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1339	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1340	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1341	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1342	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1343	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1344	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1345	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1346	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1347	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1348	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1349	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1350	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1351	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1352	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1353	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1354	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1355	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1356	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1357	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1358	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1359	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1360	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1361	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1362	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1363	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1364	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1365	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1366	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1367	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1368	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1369	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1370	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1371	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1372	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1373	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1374	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1375	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1376	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1377	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1378	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1379	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1380	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1381	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1382	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1383	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1384	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1385	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1386	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1387	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1388	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1389	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1390	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1391	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1392	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1393	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1394	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1395	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1396	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1397	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1398	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1399	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1400	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1401	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1402	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1403	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1404	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1405	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1406	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1407	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1408	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1409	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1410	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1411	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1412	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1413	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1414	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1415	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1416	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1417	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1418	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1419	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1420	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1421	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1422	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1423	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1424	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1425	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1426	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1427	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1428	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1429	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1430	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1431	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1432	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1433	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1434	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1435	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1436	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1437	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1438	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1439	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1440	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1441	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1442	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1443	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1444	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1445	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1446	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1447	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1448	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1449	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1450	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1451	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1452	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1453	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1454	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1455	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1456	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1457	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1458	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1459	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1460	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1461	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1462	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1463	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1464	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1465	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1466	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1467	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1468	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1469	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1470	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1471	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1472	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1473	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1474	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1475	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1476	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1477	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1478	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1479	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1480	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1481	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1482	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1483	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1484	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1485	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1486	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1487	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1488	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1489	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1490	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1491	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1492	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1493	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1494	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1495	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1496	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1497	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1498	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1499	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1500	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1501	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1502	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1503	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1504	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1505	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1506	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1507	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1508	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1509	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1510	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1511	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1512	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1513	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1514	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1515	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1516	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1517	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1518	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1519	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1520	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1521	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1522	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1523	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1524	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1525	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1526	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1527	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1528	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1529	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1530	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1531	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1532	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1533	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1534	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1535	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1536	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1537	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1538	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1539	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1540	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1541	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1542	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1543	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1544	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1545	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1546	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1547	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1548	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1549	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1550	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1551	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1552	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1553	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1554	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1555	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1556	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1557	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1558	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1559	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1560	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1561	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1562	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1563	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1564	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1565	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1566	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1567	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1568	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1569	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1570	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1571	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1572	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1573	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1574	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1575	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1576	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1577	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1578	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1579	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1580	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1581	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1582	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1583	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1584	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1585	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1586	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1587	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1588	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1589	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1590	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1591	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1592	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1593	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1594	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1595	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1596	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1597	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1598	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1599	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1600	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1601	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1602	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1603	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1604	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1605	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1606	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1607	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1608	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1609	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1610	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1611	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1612	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1613	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1614	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1615	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1616	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1617	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1618	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1619	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1620	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1621	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1622	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1623	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1624	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1625	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1626	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1627	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1628	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1629	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1630	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1631	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1632	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1633	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1634	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1635	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1636	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1637	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1638	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1639	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1640	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1641	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1642	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1643	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1644	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1645	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1646	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1647	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1648	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1649	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1650	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1651	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1652	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1653	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1654	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1655	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1656	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1657	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1658	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1659	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1660	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1661	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1662	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1663	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1664	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1665	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1666	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1667	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1668	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1669	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1670	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1671	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1672	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1673	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1674	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1675	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1676	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1677	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1678	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1679	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1680	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1681	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1682	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1683	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1684	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1685	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1686	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1687	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1688	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1689	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1690	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1691	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1692	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1693	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1694	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1695	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1696	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1697	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1698	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1699	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1700	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1701	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1702	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1703	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1704	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1705	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1706	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1707	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1708	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1709	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1710	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1711	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1712	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1713	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1714	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1715	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1716	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1717	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1718	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1719	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1720	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1721	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1722	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1723	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1724	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1725	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1726	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1727	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1728	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1729	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1730	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1731	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1732	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1733	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1734	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1735	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1736	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1737	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1738	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1739	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1740	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1741	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1742	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1743	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1744	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1745	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1746	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1747	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1748	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1749	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1750	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1751	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1752	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1753	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1754	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1755	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1756	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1757	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1758	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1759	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1760	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1761	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1762	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1763	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1764	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1765	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1766	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1767	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1768	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1769	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1770	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1771	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1772	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1773	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1774	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1775	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1776	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1777	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1778	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1779	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1780	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1781	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1782	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1783	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1784	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1785	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1786	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1787	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1788	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1789	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1790	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1791	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1792	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1793	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1794	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1795	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1796	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1797	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1798	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1799	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1800	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1801	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1802	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1803	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1804	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1805	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1806	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1807	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1808	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1809	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1810	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1811	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1812	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1813	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1814	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1815	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1816	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1817	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1818	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1819	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1820	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1821	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1822	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1823	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1824	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1825	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1826	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1827	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1828	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1829	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1830	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1831	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1832	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1833	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1834	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1835	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1836	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1837	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1838	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1839	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1840	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1841	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1842	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1843	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1844	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1845	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1846	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1847	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1848	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1849	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1850	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1851	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1852	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1853	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1854	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1855	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1856	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1857	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1858	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1859	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1860	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1861	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1862	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1863	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1864	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1865	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1866	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1867	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1868	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1869	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1870	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1871	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1872	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1873	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1874	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1875	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1876	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1877	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1878	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1879	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1880	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1881	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1882	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1883	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1884	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1885	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1886	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1887	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1888	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1889	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1890	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1891	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1892	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	V
1893	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1894	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1895	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1896	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1897	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1898	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1899	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1900	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1901	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1902	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1903	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1904	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1905	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1906	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1907	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1908	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1909	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1910	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1911	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1912	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1913	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1914	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1915	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1916	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
1917	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

	W	X	Y
1	PM Controls	Hg Controls	Program Code
2	Wet Scrubber | Electrostatic Precipitator		
3	Wet Scrubber | Electrostatic Precipitator		
4	Wet Scrubber | Electrostatic Precipitator		
5	Wet Scrubber | Electrostatic Precipitator		
6	Wet Scrubber | Electrostatic Precipitator		
7	Wet Scrubber | Electrostatic Precipitator		
8	Wet Scrubber | Electrostatic Precipitator		
9	Wet Scrubber | Electrostatic Precipitator		
10	Wet Scrubber | Electrostatic Precipitator		
11	Wet Scrubber | Electrostatic Precipitator		
12	Wet Scrubber | Electrostatic Precipitator		
13	Wet Scrubber | Electrostatic Precipitator		
14	Wet Scrubber | Electrostatic Precipitator		
15	Wet Scrubber | Electrostatic Precipitator		
16	Wet Scrubber | Electrostatic Precipitator		
17	Wet Scrubber | Electrostatic Precipitator		
18	Wet Scrubber | Electrostatic Precipitator		
19	Wet Scrubber | Electrostatic Precipitator		
20	Wet Scrubber | Electrostatic Precipitator		
21	Wet Scrubber | Electrostatic Precipitator		
22	Wet Scrubber | Electrostatic Precipitator		
23	Wet Scrubber | Electrostatic Precipitator		
24	Wet Scrubber | Electrostatic Precipitator		
25	Wet Scrubber | Electrostatic Precipitator		
26	Wet Scrubber | Electrostatic Precipitator		
27	Wet Scrubber | Electrostatic Precipitator		
28	Wet Scrubber | Electrostatic Precipitator		
29	Wet Scrubber | Electrostatic Precipitator		
30	Wet Scrubber | Electrostatic Precipitator		
31	Wet Scrubber | Electrostatic Precipitator		
32	Wet Scrubber | Electrostatic Precipitator		
33	Wet Scrubber | Electrostatic Precipitator		
34	Wet Scrubber | Electrostatic Precipitator		
35	Wet Scrubber | Electrostatic Precipitator		
36	Wet Scrubber | Electrostatic Precipitator		
37	Wet Scrubber | Electrostatic Precipitator		
38	Wet Scrubber | Electrostatic Precipitator		
39	Wet Scrubber | Electrostatic Precipitator		
40	Wet Scrubber | Electrostatic Precipitator		
41	Wet Scrubber | Electrostatic Precipitator		
42	Wet Scrubber | Electrostatic Precipitator		
43	Wet Scrubber | Electrostatic Precipitator		

	W	X	Y
44	Wet Scrubber | Electrostatic Precipitator		
45	Wet Scrubber | Electrostatic Precipitator		
46	Wet Scrubber | Electrostatic Precipitator		
47	Wet Scrubber | Electrostatic Precipitator		
48	Wet Scrubber | Electrostatic Precipitator		
49	Wet Scrubber | Electrostatic Precipitator		
50	Wet Scrubber | Electrostatic Precipitator		
51	Wet Scrubber | Electrostatic Precipitator		
52	Wet Scrubber | Electrostatic Precipitator		
53	Wet Scrubber | Electrostatic Precipitator		
54	Wet Scrubber | Electrostatic Precipitator		
55	Wet Scrubber | Electrostatic Precipitator		
56	Wet Scrubber | Electrostatic Precipitator		
57	Wet Scrubber | Electrostatic Precipitator		
58	Wet Scrubber | Electrostatic Precipitator		
59	Wet Scrubber | Electrostatic Precipitator		
60	Wet Scrubber | Electrostatic Precipitator		
61	Wet Scrubber | Electrostatic Precipitator		
62	Wet Scrubber | Electrostatic Precipitator		
63	Wet Scrubber | Electrostatic Precipitator		
64	Wet Scrubber | Electrostatic Precipitator		
65	Wet Scrubber | Electrostatic Precipitator		
66	Wet Scrubber | Electrostatic Precipitator		
67	Wet Scrubber | Electrostatic Precipitator		
68	Wet Scrubber | Electrostatic Precipitator		
69	Wet Scrubber | Electrostatic Precipitator		
70	Wet Scrubber | Electrostatic Precipitator		
71	Wet Scrubber | Electrostatic Precipitator		
72	Wet Scrubber | Electrostatic Precipitator		
73	Wet Scrubber | Electrostatic Precipitator		
74	Wet Scrubber | Electrostatic Precipitator		
75	Wet Scrubber | Electrostatic Precipitator		
76	Wet Scrubber | Electrostatic Precipitator		
77	Wet Scrubber | Electrostatic Precipitator		
78	Wet Scrubber | Electrostatic Precipitator		
79	Wet Scrubber | Electrostatic Precipitator		
80	Wet Scrubber | Electrostatic Precipitator		
81	Wet Scrubber | Electrostatic Precipitator		
82	Wet Scrubber | Electrostatic Precipitator		
83	Wet Scrubber | Electrostatic Precipitator		
84	Wet Scrubber | Electrostatic Precipitator		
85	Wet Scrubber | Electrostatic Precipitator		
86	Wet Scrubber | Electrostatic Precipitator		

	W	X	Y
87	Wet Scrubber | Electrostatic Precipitator		
88	Wet Scrubber | Electrostatic Precipitator		
89	Wet Scrubber | Electrostatic Precipitator		
90	Wet Scrubber | Electrostatic Precipitator		
91	Wet Scrubber | Electrostatic Precipitator		
92	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
93	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
94	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
95	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
96	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
97	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
98	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
99	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
100	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
101	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
102	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
103	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
104	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
105	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
106	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
107	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
108	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
109	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
110	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
111	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
112	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
113	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
114	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
115	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
116	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
117	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
118	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
119	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
120	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
121	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
122	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
123	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
124	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
125	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
126	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
127	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
128	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
129	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
130	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
131	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
132	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
133	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
134	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
135	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
136	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
137	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
138	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
139	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
140	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
141	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
142	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
143	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
144	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
145	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
146	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
147	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
148	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
149	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
150	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
151	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
152	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
153	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
154	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
155	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
156	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
157	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
158	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
159	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
160	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
161	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
162	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
163	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
164	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
165	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
166	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
167	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
168	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
169	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
170	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
171	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
172	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
173	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
174	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
175	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
176	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
177	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
178	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
179	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
180	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
181	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
182	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
183	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
184	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
185	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
186	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
187	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
188	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
189	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
190	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
191	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
192	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
193	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
194	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
195	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
196	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
197	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
198	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
199	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
200	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
201	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
202	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
203	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
204	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
205	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
206	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
207	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
208	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
209	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
210	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
211	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
212	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
213	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
214	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
215	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
216	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
217	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
218	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
219	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
220	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
221	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
222	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
223	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
224	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
225	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
226	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
227	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
228	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
229	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
230	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
231	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
232	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
233	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
234	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
235	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
236	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
237	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
238	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
239	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
240	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
241	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
242	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
243	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
244	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
245	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
246	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
247	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
248	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
249	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
250	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
251	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
252	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
253	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
254	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
255	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
256	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
257	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
258	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
259	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
260	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
261	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
262	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
263	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
264	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
265	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
266	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
267	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
268	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
269	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
270	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
271	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
272	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
273	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
274	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
275	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
276	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
277	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
278	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
279	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
280	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
281	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
282	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
283	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
284	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
285	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
286	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
287	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
288	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
289	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
290	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
291	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
292	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
293	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
294	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
295	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
296	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
297	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
298	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
299	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
300	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
301	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
302	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
303	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
304	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
305	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
306	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
307	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
308	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
309	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
310	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
311	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
312	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
313	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
314	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
315	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
316	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
317	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
318	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
319	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
320	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
321	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
322	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
323	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
324	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
325	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
326	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
327	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
328	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
329	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
330	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
331	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
332	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
333	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
334	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
335	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
336	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
337	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
338	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
339	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
340	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
341	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
342	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
343	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
344	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
345	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
346	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
347	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
348	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
349	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
350	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
351	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
352	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
353	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
354	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
355	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
356	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
357	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
358	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
359	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
360	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
361	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
362	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
363	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
364	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
365	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
366	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
367	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
368	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
369	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
370	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
371	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
372	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
373	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
374	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
375	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
376	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
377	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
378	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
379	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
380	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
381	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
382	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
383	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
384	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
385	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
386	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
387	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
388	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
389	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
390	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
391	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
392	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
393	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
394	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
395	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
396	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
397	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
398	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
399	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
400	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
401	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
402	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
403	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
404	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
405	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
406	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
407	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
408	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
409	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
410	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
411	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
412	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
413	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
414	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
415	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
416	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
417	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
418	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
419	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
420	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
421	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
422	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
423	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
424	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
425	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
426	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
427	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
428	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
429	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
430	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
431	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
432	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
433	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
434	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
435	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
436	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
437	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
438	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
439	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
440	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
441	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
442	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
443	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
444	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
445	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
446	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
447	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
448	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
449	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
450	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
451	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
452	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
453	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
454	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
455	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
456	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
457	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
458	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
459	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
460	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
461	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
462	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
463	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
464	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
465	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
466	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
467	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
468	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
469	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
470	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
471	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
472	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
473	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
474	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
475	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
476	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
477	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
478	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
479	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
480	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
481	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
482	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
483	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
484	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
485	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
486	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
487	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
488	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
489	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
490	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
491	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
492	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
493	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
494	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
495	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
496	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
497	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
498	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
499	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
500	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
501	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
502	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
503	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
504	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
505	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
506	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
507	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
508	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
509	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
510	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
511	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
512	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
513	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
514	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
515	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
516	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
517	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
518	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
519	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
520	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
521	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
522	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
523	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
524	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
525	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
526	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
527	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
528	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
529	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
530	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
531	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
532	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
533	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
534	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
535	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
536	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
537	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
538	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
539	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
540	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
541	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
542	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
543	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
544	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
545	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
546	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
547	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
548	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
549	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
550	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
551	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
552	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
553	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
554	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
555	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
556	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
557	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
558	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
559	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
560	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
561	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
562	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
563	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
564	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
565	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
566	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
567	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
568	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
569	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
570	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
571	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
572	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
573	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
574	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
575	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
576	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
577	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
578	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
579	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
580	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
581	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
582	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
583	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
584	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
585	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
586	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
587	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
588	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
589	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
590	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
591	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
592	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
593	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
594	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
595	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
596	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
597	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
598	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
599	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
600	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
601	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
602	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
603	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
604	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
605	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
606	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
607	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
608	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
609	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
610	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
611	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
612	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
613	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
614	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
615	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
616	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
617	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
618	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
619	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
620	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
621	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
622	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
623	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
624	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
625	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
626	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
627	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
628	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
629	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
630	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
631	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
632	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
633	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
634	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
635	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
636	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
637	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
638	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
639	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
640	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
641	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
642	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
643	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
644	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
645	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
646	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
647	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
648	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
649	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
650	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
651	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
652	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
653	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
654	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
655	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
656	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
657	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
658	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
659	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
660	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
661	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
662	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
663	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
664	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
665	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
666	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
667	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
668	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
669	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
670	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
671	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
672	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
673	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
674	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
675	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
676	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
677	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
678	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
679	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
680	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
681	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
682	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
683	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
684	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
685	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
686	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
687	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
688	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
689	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
690	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
691	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
692	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
693	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
694	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
695	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
696	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
697	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
698	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
699	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
700	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
701	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
702	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
703	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
704	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
705	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
706	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
707	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
708	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
709	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
710	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
711	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
712	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
713	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
714	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
715	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
716	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
717	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
718	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
719	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
720	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
721	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
722	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
723	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
724	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
725	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
726	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
727	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
728	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
729	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
730	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
731	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
732	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
733	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
734	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
735	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
736	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
737	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
738	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
739	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
740	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
741	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
742	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
743	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
744	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
745	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
746	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
747	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
748	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
749	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
750	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
751	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
752	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
753	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
754	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
755	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
756	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
757	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
758	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
759	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
760	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
761	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
762	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
763	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
764	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
765	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
766	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
767	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
768	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
769	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
770	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
771	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
772	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
773	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
774	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
775	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
776	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
777	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
778	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
779	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
780	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
781	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
782	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
783	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
784	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
785	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
786	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
787	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
788	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
789	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
790	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
791	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
792	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
793	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
794	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
795	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
796	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
797	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
798	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
799	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
800	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
801	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
802	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
803	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
804	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
805	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
806	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
807	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
808	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
809	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
810	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
811	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
812	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
813	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
814	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
815	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
816	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
817	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
818	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
819	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
820	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
821	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
822	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
823	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
824	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
825	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
826	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
827	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
828	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
829	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
830	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
831	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
832	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
833	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
834	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
835	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
836	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
837	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
838	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
839	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
840	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
841	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
842	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
843	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
844	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
845	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
846	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
847	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
848	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
849	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
850	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
851	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
852	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
853	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
854	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
855	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
856	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
857	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
858	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
859	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
860	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
861	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
862	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
863	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
864	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
865	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
866	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
867	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
868	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
869	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
870	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
871	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
872	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
873	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
874	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
875	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
876	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
877	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
878	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
879	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
880	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
881	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
882	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
883	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
884	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
885	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
886	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
887	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
888	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
889	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
890	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
891	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
892	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
893	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
894	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
895	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
896	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
897	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
898	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
899	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
900	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
901	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
902	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
903	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
904	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
905	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
906	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
907	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
908	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
909	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
910	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
911	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
912	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
913	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
914	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
915	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
916	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
917	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
918	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
919	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
920	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
921	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
922	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
923	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
924	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
925	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
926	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
927	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
928	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
929	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
930	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
931	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
932	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
933	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
934	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
935	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
936	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
937	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
938	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
939	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
940	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
941	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
942	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
943	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
944	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
945	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
946	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
947	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
948	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
949	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
950	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
951	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
952	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
953	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
954	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
955	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
956	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
957	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
958	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
959	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
960	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
961	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
962	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
963	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
964	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
965	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
966	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
967	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
968	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
969	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
970	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
971	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
972	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
973	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
974	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
975	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
976	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
977	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
978	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
979	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
980	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
981	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
982	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
983	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
984	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
985	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
986	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
987	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
988	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
989	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
990	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
991	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
992	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
993	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
994	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
995	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
996	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
997	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
998	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
999	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1000	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1001	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1002	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1003	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1004	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1005	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1006	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1007	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1008	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1009	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1010	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1011	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1012	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1013	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1014	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1015	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1016	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1017	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1018	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1019	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1020	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1021	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1022	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1023	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1024	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1025	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1026	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1027	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1028	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1029	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1030	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1031	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1032	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1033	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1034	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1035	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1036	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1037	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1038	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1039	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1040	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1041	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1042	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1043	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1044	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1045	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1046	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1047	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1048	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1049	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1050	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1051	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1052	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1053	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1054	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1055	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1056	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1057	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1058	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1059	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1060	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1061	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1062	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1063	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1064	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1065	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1066	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1067	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1068	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1069	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1070	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1071	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1072	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1073	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1074	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1075	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1076	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1077	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1078	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1079	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1080	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1081	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1082	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1083	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1084	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1085	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1086	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1087	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1088	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1089	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1090	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1091	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1092	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1093	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1094	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1095	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1096	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1097	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1098	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1099	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1100	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1101	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1102	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1103	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1104	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1105	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1106	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1107	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1108	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1109	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1110	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1111	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1112	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1113	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1114	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1115	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1116	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1117	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1118	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1119	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1120	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1121	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1122	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1123	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1124	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1125	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1126	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1127	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1128	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1129	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1130	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1131	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1132	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1133	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1134	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1135	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1136	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1137	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1138	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1139	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1140	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1141	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1142	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1143	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1144	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1145	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1146	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1147	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1148	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1149	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1150	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1151	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1152	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1153	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1154	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1155	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1156	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1157	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1158	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1159	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1160	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1161	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1162	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1163	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1164	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1165	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1166	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1167	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1168	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1169	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1170	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1171	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1172	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1173	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1174	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1175	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1176	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1177	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1178	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1179	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1180	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1181	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1182	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1183	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1184	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1185	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1186	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1187	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1188	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1189	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1190	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1191	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1192	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1193	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1194	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1195	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1196	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1197	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1198	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1199	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1200	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1201	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1202	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1203	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1204	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1205	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1206	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1207	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1208	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1209	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1210	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1211	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1212	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1213	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1214	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1215	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1216	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1217	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1218	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1219	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1220	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1221	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1222	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1223	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1224	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1225	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1226	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1227	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1228	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1229	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1230	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1231	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1232	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1233	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1234	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1235	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1236	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1237	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1238	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1239	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1240	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1241	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1242	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1243	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1244	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1245	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1246	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1247	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1248	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1249	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1250	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1251	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1252	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1253	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1254	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1255	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1256	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1257	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1258	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1259	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1260	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1261	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1262	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1263	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1264	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1265	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1266	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1267	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1268	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1269	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1270	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1271	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1272	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1273	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1274	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1275	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1276	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1277	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1278	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1279	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1280	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1281	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1282	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1283	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1284	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1285	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1286	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1287	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1288	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1289	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1290	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1291	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1292	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1293	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1294	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1295	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1296	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1297	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1298	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1299	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1300	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1301	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1302	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1303	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1304	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1305	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1306	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1307	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1308	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1309	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1310	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1311	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1312	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1313	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1314	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1315	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1316	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1317	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1318	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1319	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1320	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1321	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1322	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1323	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1324	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1325	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1326	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1327	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1328	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1329	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1330	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1331	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1332	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1333	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1334	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1335	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1336	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1337	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1338	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1339	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1340	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1341	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1342	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1343	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1344	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1345	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1346	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1347	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1348	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1349	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1350	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1351	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1352	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1353	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1354	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1355	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1356	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1357	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1358	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1359	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1360	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1361	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1362	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1363	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1364	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1365	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1366	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1367	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1368	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1369	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1370	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1371	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1372	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1373	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1374	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1375	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1376	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1377	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1378	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1379	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1380	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1381	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1382	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1383	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1384	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1385	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1386	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1387	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1388	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1389	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1390	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1391	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1392	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1393	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1394	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1395	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1396	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1397	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1398	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1399	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1400	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1401	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1402	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1403	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1404	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1405	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1406	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1407	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1408	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1409	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1410	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1411	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1412	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1413	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1414	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1415	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1416	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1417	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1418	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1419	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1420	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1421	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1422	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1423	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1424	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1425	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1426	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1427	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1428	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1429	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1430	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1431	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1432	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1433	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1434	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1435	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1436	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1437	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1438	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1439	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1440	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1441	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1442	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1443	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1444	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1445	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1446	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1447	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1448	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1449	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1450	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1451	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1452	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1453	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1454	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1455	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1456	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1457	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1458	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1459	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1460	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1461	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1462	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1463	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1464	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1465	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1466	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1467	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1468	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1469	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1470	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1471	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1472	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1473	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1474	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1475	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1476	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1477	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1478	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1479	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1480	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1481	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1482	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1483	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1484	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1485	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1486	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1487	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1488	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1489	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1490	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1491	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1492	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1493	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1494	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1495	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1496	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1497	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1498	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1499	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1500	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1501	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1502	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1503	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1504	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1505	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1506	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1507	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1508	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1509	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1510	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1511	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1512	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1513	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1514	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1515	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1516	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1517	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1518	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1519	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1520	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1521	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1522	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1523	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1524	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1525	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1526	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1527	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1528	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1529	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1530	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1531	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1532	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1533	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1534	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1535	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1536	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1537	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1538	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1539	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1540	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1541	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1542	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1543	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1544	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1545	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1546	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1547	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1548	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1549	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1550	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1551	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1552	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1553	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1554	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1555	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1556	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1557	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1558	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1559	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1560	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1561	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1562	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1563	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1564	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1565	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1566	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1567	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1568	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1569	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1570	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1571	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1572	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1573	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1574	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1575	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1576	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1577	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1578	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1579	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1580	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1581	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1582	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1583	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1584	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1585	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1586	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1587	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1588	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1589	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1590	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1591	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1592	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1593	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1594	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1595	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1596	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1597	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1598	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1599	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1600	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1601	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1602	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1603	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1604	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1605	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1606	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1607	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1608	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1609	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1610	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1611	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1612	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1613	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1614	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1615	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1616	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1617	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1618	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1619	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1620	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1621	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1622	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1623	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1624	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1625	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1626	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1627	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1628	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1629	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1630	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1631	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1632	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1633	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1634	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1635	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1636	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1637	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1638	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1639	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1640	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1641	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1642	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1643	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1644	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1645	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1646	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1647	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1648	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1649	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1650	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1651	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1652	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1653	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1654	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1655	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1656	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1657	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1658	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1659	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1660	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1661	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1662	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1663	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1664	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1665	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1666	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1667	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1668	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1669	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1670	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1671	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1672	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1673	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1674	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1675	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1676	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1677	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1678	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1679	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1680	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1681	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1682	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1683	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1684	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1685	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1686	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1687	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1688	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1689	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1690	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1691	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1692	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1693	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1694	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1695	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1696	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1697	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1698	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1699	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1700	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1701	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1702	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1703	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1704	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1705	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1706	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1707	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1708	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1709	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1710	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1711	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1712	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1713	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1714	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1715	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1716	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1717	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1718	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1719	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1720	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1721	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1722	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1723	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1724	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1725	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1726	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1727	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1728	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1729	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1730	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1731	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1732	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1733	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1734	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1735	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1736	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1737	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1738	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1739	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1740	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1741	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1742	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1743	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1744	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1745	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1746	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1747	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1748	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1749	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1750	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1751	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1752	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1753	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1754	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1755	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1756	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1757	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1758	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1759	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1760	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1761	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1762	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1763	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1764	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1765	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1766	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1767	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1768	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1769	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1770	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1771	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1772	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1773	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1774	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1775	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1776	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1777	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1778	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1779	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1780	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1781	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1782	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1783	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1784	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1785	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1786	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1787	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1788	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1789	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1790	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1791	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1792	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1793	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1794	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1795	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1796	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1797	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1798	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1799	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1800	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1801	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1802	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1803	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1804	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1805	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1806	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1807	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1808	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1809	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1810	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1811	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1812	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1813	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1814	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1815	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1816	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1817	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1818	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1819	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1820	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1821	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1822	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1823	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1824	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1825	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1826	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1827	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1828	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1829	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1830	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1831	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1832	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1833	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1834	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1835	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1836	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1837	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1838	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1839	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1840	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1841	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1842	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1843	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1844	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1845	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1846	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1847	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1848	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1849	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1850	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1851	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1852	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1853	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1854	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1855	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1856	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1857	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1858	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1859	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1860	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1861	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1862	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1863	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1864	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1865	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1866	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1867	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1868	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1869	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1870	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1871	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1872	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1873	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1874	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1875	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1876	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1877	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1878	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1879	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1880	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1881	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1882	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1883	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1884	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1885	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1886	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1887	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1888	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1889	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1890	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1891	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1892	Wet Scrubber | Electrostatic Precipitator		ARP, MATS

	W	X	Y
1893	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1894	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1895	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1896	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1897	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1898	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1899	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1900	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1901	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1902	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1903	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1904	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1905	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1906	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1907	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1908	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1909	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1910	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1911	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1912	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1913	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1914	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1915	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1916	Wet Scrubber | Electrostatic Precipitator		ARP, MATS
1917	Wet Scrubber | Electrostatic Precipitator		ARP, MATS