

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-26-31

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

Exhibit LL: Division, *Technical Review Document for
Operating Permit 96OPMF155* (Jan. 2005)

TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPMF155
to be issued to:

Tri-State Generation & Transmission Association
Craig Station
Moffat County
Source ID 0810018

Cathy Rhodes
May, 2002
Revised January, 2005

I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. This narrative is intended only as an adjunct for the reviewer and has no legal standing. The conclusions made in this report are based on information provided in the original application submittal of February 23, 1996 and the revised application submittal of January 4, 1999, and additional information received on October 21, 1999 and August 31, 2001.

Any revisions made to the underlying construction permits associated with this facility in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or an additional or revised Construction Permit.

II. SOURCE DESCRIPTION:

This facility is located in Craig, Moffat County, Colorado. The area is classified as an attainment area for all pollutants. Wyoming is an affected state within 50 miles of the facility. There are two Federal Class I areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument, although not a Class I area, is within 100 kilometers of the facility, and has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

The entire plant is categorized as a major stationary source for the Prevention of Significant Deterioration (PSD) provisions. The EPA issued a PSD permit for Unit 3 on March 26,

1980. Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part A, Section I.B.37 and 58) for any pollutant listed in Colorado Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

The Craig Station consists of three coal fired steam driven electric generating units (Units 1, 2, and 3). Total net electric generating capacity is 1264 MW. Natural gas, propane and fuel oil are used as secondary fuels for flame stabilization, startup and shutdown. All three units are subject to the provisions of Title IV, the Acid Rain Program, of the Clean Air Act. Units 1 & 2 PM emissions were controlled by ESPs and wet limestone scrubbers control SO₂ emissions. Under a January 10, 2001 Consent Order, the ESPs have been replaced with baghouses and the wet scrubbers were upgraded. A baghouse controls PM emissions, and a spray dry scrubber controls SO₂ emissions from Unit 3. All three units have low-NO_x burners to control NO_x emissions. Overfire air and related NO_x control upgrades are now in place for Unit 1 and Unit 2. This permit currently only covers Units 1 and 2 and associated equipment. This permit does not currently cover Unit 3 or its associated equipment (except for coal handling, which may at times also serve Units 1 and 2). Associated activities covered by the permit include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area, as well as numerous insignificant activities.

Unit 3 is currently operating under the provisions of an EPA-issued PSD permit (issued on March 26, 1980, revised January 12, 1981, and August 14, 1992) and State-issued Construction permits 12MF322(1-4) and 98MF0141. The draft version of this permit that went to Public Comment on May 17, 2001 as well as the Proposed version of the permit that went to EPA on September 13, 2004 covered all three boilers. Prior to the Public Comment period, EPA, the Division, and Tri-State had discussions regarding the interpretation of several conditions of the EPA PSD permit. Following Public Comment, discussions continued on two issues: Range Z and the applicability of the BACT limits during periods of startup, shutdown, and malfunction (s/s/m). The root of the issues lies with imprecise and confusing language that was put into the PSD permit when it was issued some 25 years ago. Some of the issues were not resolved, and EPA sent a formal objection letter to the Division on October 22, 2004, citing the remaining unresolved issues.

Under the provisions of Regulation No. 3, Part C, § VI.H, the Division has 90 days in which to submit a revised permit to EPA after a formal objection letter is received. During the 90 day period, Tri-State indicated that they were planning on submitting an application to the Division for a major PSD modification to Unit 3 sometime in April 2005. State statutes and Federal regulations provide for the Air Pollution Control Division ("APCD") to issue PSD permits for major modifications made after September 2, 1986. Section 25-7-210 C.R.S. states:

Sections 25-7-201 and 25-7-203 to 25-7-206 shall apply only to applications for proposed new major stationary sources and major modifications which are submitted on or after the date of approval by the United States

environmental protection agency of the program for prevention of significant deterioration embodied in the state implementation plan.

Thus the March application will result in a new PSD Construction permit for Unit 3 and associated activities. The new permit will replace the existing PSD permit, and will address the provisions upon which the EPA's objection was based.

Since a new PSD permit will be issued in the near future, the Division and the EPA have agreed that the Division will at this time issue a revised Operating Permit which contains only the requirements for Units 1 and 2. The Unit 3 requirements will be added to this operating permit once the new PSD permit is issued. The EPA and the Division believe that this is the best and most expedient method to resolve the existing PSD permit concerns and the EPA objections regarding the initially proposed operating permit. The new PSD permit will be issued using the appropriate procedures in Regulation No. 3, including public notice and participation requirements. Under Regulation No. 3, Part C provisions, the applicant must apply for a modification to incorporate the new PSD permit requirements into their operating permit within twelve months of startup of the modified Unit 3. The revised Operating Permit will be issued using the Significant Modification procedures of Regulation No. 3, Part C, including public notice and participation requirements and EPA review.

The following Potential-to-Emit and actual 1997 emissions data are based on information supplied in the Title V application (rounded figures – includes all three units and all associated activities).

	POTENTIAL TO EMIT, TONS PER YEAR					
	PM	PM ₁₀	SO ₂	NO _x	VOC	CO
B001 - Unit 1	1891	435	22695	13239	60	498
B002 - Unit 2	1891	435	22695	13239	60	498
B003 - Unit 3	566	130	3770	9426	58	484
P101 - Coal Handling Units 1 & 2	41	18				
P102 - Coal Handling Unit 3	2	1				
P201 - Limestone Handling Units 1 & 2	14	3				
P202 - Lime Handling Unit 3	23	6				

P203 - Ash Handling Units 1 & 2	neg	Neg				
P204 - Ash Handling and Ash Haul Roads Unit 3	115	30				
P205 – Landfill	4	1				
P401 - Unit 1 CT	14	14			5	
P402 - Unit 2 CT	14	14			5	
P403 - Unit 3 CT	14	14			5	
Total	4588	1101	49160	35904	194	1479
FACILITY 1997 ACTUAL EMISSIONS TPY	772	250	10094	15750	133	1110

CT = Cooling Tower

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

B001 - Unit #1 - Babcock & Wilcox Boiler

B002 – Unit #2- Babcock & Wilcox Boiler

Applicable Requirements - Final Approval Construction Permit 10MF579 was issued for Units 1 and 2. Applicable requirements are as follows.

Construction Permit 10MF579

- This source is subject to the requirements of the New Source Performance Standards for Fossil Fuel Fired Steam Generators, as in effect May 1, 1973.

Construction Permit 10MF579 indicates that the Units are subject to the NSPS as it existed on May 1, 1973. This is because the units were permitted when Subpart D was in the proposal process, and had not been finalized by the EPA. Subsequently, the EPA finalized the rule, and it applies to all sources constructed, reconstructed, or modified after August 17, 1971. The rule does not provide for any exceptions for sources constructed prior to final promulgation, therefore, Units 1

and 2 are subject to the most current version of Subpart D. This revision to the Construction Permit is incorporated directly into this operating permit through a combined Construction Permit/Operating Permit procedure. Note: The EPA did not promulgate startup, shutdown, and malfunction provisions until October 15, 1973.

- Emissions of sulfur dioxide shall not exceed 1.2 pounds per million Btu heat input, maximum 3 hour average.
- Visible emissions shall not exceed 20 percent opacity.
- Emissions of particulate matter shall not exceed 0.1 pounds per million Btu heat input, maximum 2 hour average. *On June 14, 1974, the EPA revised Subpart D to change the sampling time requirements for PM from a minimum of 2 hours to a minimum of 60 minutes per run, to make the provision consistent with 60.8(f). The sampling interval specified in 60.46 was shortened to be consistent with the 60-minute-per-run requirement. The preamble to this revision states that these actions are intended for clarification and for maintaining consistency throughout the regulations. They are not intended to alter the substantive content of the regulations. Thus, the 2 hour averaging time no longer applies to Units 1 and 2.*
- Emissions of nitrogen oxides shall not exceed 0.7 pounds per million Btu heat input, maximum 3 hour average.
- This source shall comply with all applicable monitoring, notification, and record keeping requirements of the New Source Performance Standards (Regulation 6) and Regulation 1. IV.
- This source is subject to the requirements of Regulation 6. Section I., including Section I.4 which states: At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

- A Revised Air Pollutant Emission Notice shall be filed when a significant change in emissions occurs, as required by Regulation No.3.II.B.

Colorado Regulation No. 1

- Except as provided in Section II.A.4, opacity shall not exceed 20% (Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or cleaning of control equipment (Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu heat input (Section III. A.1.c)
- Continuous emission monitoring (Section IV)
- Continuous Opacity Monitor (COM) requirements (Section IV.B.1)
- Continuous Emission Monitor (CEM) for SO₂ or fuel sampling (Section IV.B.2)
- If CEM for SO₂ then CEM for either O₂ or CO₂ (Section IV.B.3)
- Calibration of CEMs (Section IV.F)
- Notification and Recordkeeping (Section IV.G)
- Recordkeeping duration (Section IV.H)
- Reporting requirements - if fuel sampling (Section IV.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu heat input (Section VI.A.3.a.(ii)), based on a 3 hour rolling average

Colorado Regulation No. 8, Part C

- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 µg/scm averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement

NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)

- Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu heat input
- Opacity shall not exceed 20%, except for one six-minute period of not more than 27% - does not apply during start-up, shutdown and malfunction
- SO₂ emissions shall not exceed 1.2 lbs/mmBtu heat input when burning coal, 3 hour average
- NO_x emissions shall not exceed 0.70 lbs/mmBtu heat input when burning coal, 3 hour average

- Source shall install, calibrate, maintain and operate continuous monitoring systems for measuring opacity, SO₂ and NO_x emissions and either O₂ or CO₂

PM, SO₂, and NO_x emission limits do not apply during startup, shutdown, or malfunction. (See October 15, 1973 Federal Register)

Acid Rain (Title IV) Requirements

- The Code of Federal Regulations lists 8153 (Unit 1) and 7785 (Unit 2) SO₂ allowances (as listed in 40 CFR 73.10(b)) for these sources. Note that additional allowances can be obtained as needed per 40 CFR Part 75. The units will be allocated 8153 and 7785 allowances per year from 2000 to 2009 (as listed in the EPA's "Allowances Held Report," January 4, 1999).
- NO_x emissions of 0.50 lbs/mmBtu heat input, on an annual average basis (source opted to comply with Phase I limits (§76.5(a)(2) by early election (§ 76.8), which went into effect January 1, 1997).
- Acid rain permitting requirements per 40 CFR Part 72.
- Continuous emission monitoring requirements per 40 CFR Part 75.
- The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

January 10, 2001 Consent Decree Requirements

- Requires replacement of ESPs at Units 1 and 2 with baghouses, FGD upgrades, and installation of NO_x emission control upgrades by certain dates
- PM emissions from Units 1 and 2 shall not exceed 0.03 lb/mmBtu heat input by certain dates
- SO₂ emissions from Units 1 and 2 shall not exceed 0.160 lb/mmBtu heat input, on a 30 day rolling average and 0.130 lb/mmBtu heat input on a 90 day rolling average, by certain dates
- SO₂ emissions from Units 1 and 2 shall be controlled by either 86% on a 30 day rolling average, or 90% on a 90 day rolling average, by certain dates, unless a "showing" is made
- NO_x emissions from Units 1 and 2 shall not exceed 0.30 lb/mmBtu heat input on an annual average basis, by certain dates
- Limits opacity as follows: (1) 20% averaged over each separate 6-minute period at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for more than 6 minutes in any 60 consecutive minutes; (2) 30% for more than 6 minutes during any 60 consecutive minutes during any startup; (3) 20% during any

shutdown, unless excused by an upset condition; (4) 20% except for one six minute period per hour of not more than 27% opacity as averaged over each separate 6-minute period with an hour, beginning each hour on the hour. Emissions during startup, shutdown and malfunction are excused under this opacity limit.

- Requires stack testing for PM
- Requires installation and operation of continuous opacity monitors and continuous monitors for SO₂ emissions, NO_x emissions, CO₂, and flow
- Requires permittee to operate Units 1 and 2 using good operating practices

Note: Since this permit went to public notice, the milestones for various Consent Decree requirements have passed. The permit is therefore revised to delete those due dates and obsolete requirements related to the ESPs.

Consent Decree Requirements as a Pollution Control Project

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the FGD upgrades do not result in an increase in emissions. The NO_x emission control upgrades may decrease NO_x emissions substantially but increase CO emissions slightly. In the case of Craig Units 1 and 2, the addition of control equipment is required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NO_x emission control upgrades. Therefore, the Division does not believe it is appropriate to include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the NO_x emission control upgrades.

Effect of Incorporation of Consent Decree into the Operating Permit

The Consent Decree requirements were approved by the EPA as part of the Colorado State implementation Plan and are applicable requirements which must be included in the operating permit. Under terms of the Consent Decree, upon issuance of this operating permit, the Division assumes certain compliance/enforcement provisions of the Decree. As for any applicable requirement incorporated into an operating permit, nothing in the permit is intended to have the effect of relaxing any requirement in the Consent Decree or to change or modify any rights of the parties to that decree.

Voluntary Emission Reduction Agreement (VERA)

In 2001, a VERA was completed for Units 1 and 2, to reduce emissions which affect visibility and air quality related values. VERA's normally include specific emission limits and related requirements, and are included as applicable requirements in operating permits. In this case, the VERA states that the Division finds and determines that the provisions of the Consent Decree meet the requirements for a VERA for Units 1 and 2. Therefore, this VERA

is not incorporated into the operating permit, since the Consent Decree requirements are incorporated.

Emission Factors - The combustion of coal in the boilers results in emissions of NO_x, SO₂, PM, PM₁₀, CO, VOC, and Pb. CEMs are used to determine compliance with emission standards and to estimate annual emissions of NO_x and SO₂. For PM and PM₁₀, stack test results and monitored heat content of the fuel are used to determine compliance and estimate annual emissions. Standard factors from the AP-42 manual, or other emission factors/procedures acceptable to the Division (see Regulation No. 3, Part A, II.B.1 for acceptable alternative methods) along with appropriate removal efficiencies for control equipment, are used to estimate CO, VOC, HAP and Pb emissions.

Monitoring Plan - CEMs are used to demonstrate compliance with the NO_x and SO₂ lb/mmBtu limits. Stack testing and a baghouse and wet scrubber maintenance plan are used to demonstrate compliance with the PM limits. The required frequency for PM stack testing will be reduced, if the source meets criteria based on the test results in relation to the emission standard, as set forth in the permit. The heat content of the fuel is needed for these determinations. The heat input can be calculated from the carbon dioxide CEM required under the Acid Rain Program, or measured through a coal sampling plan, or vendor information.

Compliance with opacity limits is demonstrated using a COM.

Scales are used to measure the amount of coal combusted in the boiler. These data are used to estimate PM, PM₁₀, CO, VOC, and HAP emissions.

The permittee performed a one-time modeling exercise which demonstrated compliance with the Regulation No. 8 lead requirements.

Compliance Status - The Division accepts these Units were in compliance at the time the Title V application was submitted. In addition, the most recent inspection report indicates the Units were in compliance at the time of inspection.

B001 - Unit #1 - Babcock & Wilcox Boiler
- Natural Gas, Propane, and Fuel Oil
B002 - Unit #2 - Babcock & Wilcox Boiler
- Natural Gas, Propane, and Fuel Oil

Coal is the primary fuel for these boilers. Secondary fuels (natural gas, propane, or fuel oil) are used during non-routine periods such as startup and shutdown, adding to or removing coal pulverizers from service, or other flame stability efforts.

Applicable Requirements - The Construction Permit did not address secondary fuels. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion. The

permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas, propane or fuel oil remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 5% of total heat input. If alternate fuel use comprises more than 5% of total heat input on an annual basis, the permit must be reopened to include Subpart D requirements for combined fuel combustion. In addition, this source is subject to Regulation No. 1 emission limits, which are equal to or less stringent than Subpart D provisions. The Division therefore also assumes the source is in compliance with Regulation No. 1 requirements whenever alternate fuel use comprises less than 1% of total heat input.

Alternate Operating Scenarios

The permittee requested the ability to dispose of spent boiler tube cleaning waste as an alternate operating scenario. Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. The cleaning is accomplished by circulating cleaning solutions, generally acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. The permittee had previously requested to dispose of cleaning waste in the boiler, in March of 1993. At that time the Division agreed to the proposal, and determined a modification to the Construction Permit was not necessary. The permittee provided information regarding studies performed by the Electric Power Research Institute which indicates that disposal of cleaning wastes does not have a significant effect on operations or emissions. This has been an on-going practice for boilers operated by utilities, and has not been cited by the Division as a compliance issue.

In addition, the permittee indicates that on a sporadic basis, they wish to combust non-hazardous petroleum contaminated soils and materials in the boiler. These materials are generated on occasions at the Craig Station when accidental spills of petroleum liquids (lube oils and fuel) occur. Because of the expected small quantity of non-hazardous petroleum contaminated soils and materials generated, it is expected that introduction of such materials into the boiler for combustion will not cause the exceedance of any applicable emission limit or emission of pollutants not generated by routine operation of these boilers.

Provisions for these two alternate operating scenarios are provided for in the Operating Permit.

P101 – Coal Handling – Units 1 & 2

The Unit 1 and 2 coal handling system transfers coal delivered by trucks on unpaved haul roads to Craig Station to the Unit 1, 2, and 3 coal storage piles and silos. On occasion, coal is deposited in a coal surge pile prior to being transferred to the crusher. The coal is

crushed and conveyed to the coal transfer building, where it is sent either to the stockpiles or coal silos. Coal destined for the storage pile is conveyed to the stackout tower and then to telescoping chutes for loadout to the storage pile. Coal is reclaimed underground from storage and is transferred to generation building coal silos. Bagfilters and enclosed conveyors control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles. Telescopic chutes are used to control PM emissions from the coal pile stackout. Coal unloading and stackout is controlled with water spray containing a surfactant, on an as-needed basis. Note that water sprays may not be operable during cold weather. The coal haul road is treated with a resinous adhesive, or equivalent, as often as necessary.

Applicable Requirements - Final Construction Permit 11MF276 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF276

- Limits process throughput to 3,900,000 tons per year
- Limits opacity to 20%
- Sets forth measures for minimizing fugitive particulate matter emissions

Requested revisions:

"The coal being loaded to live storage will be sprayed with water with a surfactant added," is revised to read: "The coal being loaded to live storage will be sprayed with water with a surfactant added, on an as-needed basis." This is consistent with other Tri-State construction permits.

"The haul road used by coal trucks on the Craig Station property shall be treated with a resinous adhesive (or equivalent) to control dust. The treatment material shall be bladed into the soil according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure." Is revised to read: "The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure."

The requirement for water spray bars at the unloading station is revised to indicate that the spray bars will be used *as needed*.

Regulation No.1.II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." The Division has determined that the emissions from the coal pile stackout telescopic chute are fugitive.) Other fugitive sources include the storage piles, unloading to the grizzly, unloading to the coal surge pile, and the haul road.

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% for all sources except the storage piles, unloading to coal surge pile, coal pile stackout and coal stackout building, coal reclaim A & B, coal tripper deck and silos, common coal drive house, and haul roads - Not applicable during startup, shutdown, or malfunction

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the truck unloading hoppers to the units or stockpile, and from the stockpile to the coal silos. These monitoring records can be used to identify compliance with the coal handling limits. The emissions are calculated based on the amount of coal being processed.

For those sources subject to an opacity standard, a U.S. EPA Reference Method 9 opacity observation is performed by a certified observer at least semi-annually. An operation and maintenance plan shall be implemented for the baghouses.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts this process was in compliance at the time the Title V application was submitted.

P102 – Coal Handling – Unit 3

The Unit 3 coal handling system transfers coal delivered by rail car to the Unit 1,2, and 3 coal piles and silos. Coal drops from the railcars into underground hoppers and is conveyed to the crusher building. After crushing, coal is conveyed to the stackout building, where it is either sent to the stockpile or to the transfer building. Coal in the transfer building is conveyed to the coal silos in the generation building. Bagfilters control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles.

Telescopic chutes are used to control PM emissions from the coal pile stackout. Water is sprayed at the coal train unloading to control PM emissions. Note that water sprays may not be operable during cold weather. Water, compaction or chemicals are used, as necessary, to control PM emissions at the coal storage piles. Since the Unit 3 system handles coal which may be delivered to Units 1 and 2, the system is included in the Operating Permit at this time.

Applicable Requirements - Final Construction Permit 12MF322(2) was issued for these sources. Applicable requirements are as follows.

Construction Permit 12MF322(2)

- Limits opacity to 20%
- Sets forth measures for minimizing fugitive PM emissions
- Requires emissions from crushing, transferring, and coal reclaiming to be controlled by fabric filter baghouses

Colorado Regulation No.1.II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (*Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." Fugitive sources include coal train unloading, coal stackout, and storage piles.*)

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% - Not applicable during startup, shutdown, or malfunction - Does not apply to coal stackout, common coal transfer building extension, common coal drive house, coal tripper deck and silos, to the storage pile, or to the open coal storage pile

Other

The Construction Permit does not contain a specific processing limit, however, records of the amount of coal processed are necessary for estimating emissions.

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the rail cars unloading hoppers to the Units or stockpile, and from the stockpile to the coal silos. The emissions are calculated based on the amount of coal being processed. A U.S. EPA Reference Method 9 opacity observation is performed by a certified observer every six months and a baghouse operating and maintenance plan is required.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P201 – Limestone Handling and Storage Facility – Units 1 & 2

The Unit 1 & 2 limestone handling system provides for receiving, transferring, storage, and preparation of limestone before it is introduced to the Units 1 & 2 wet limestone scrubbers. Limestone is delivered by trucks, and unloaded to a receiving hopper. Limestone is then transferred to the silos. Bagfilters are used to control PM emissions at the silo and unloading.

Applicable Requirements - Final Construction Permit 11MF415 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF415

- Limits opacity to 20%
- Requires unloading facilities emissions to be controlled by baghouse
Construction Permit requirement is revised from: "All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system." To: "All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system."

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: limestone hauling.

Other

The Construction Permit does not specifically limit the amount of limestone delivered, however, the amount is needed to calculate emissions estimates

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions

Monitoring Plan -Semi-annual U.S. EPA Reference Method 9 opacity observations will be performed on the baghouses and a baghouse operation and maintenance plan is required.

Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

P203 – Ash Handling System – Units 1 & 2

The Unit 1 and 2 ash handling and processing system provides for transferring ash from the boilers and ESPs to ash silos for temporary storage before it is transported for off-site disposal or commercial sale. The Unit 1 and 2 boilers generate both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Fly ash is pneumatically transported to the silos. Bagfilters are used to control PM emissions for the silos and the dry ash unloading for commercial sale. Water and dustless unloaders are used to control PM for truck loading operations for ash disposal.

Applicable Requirements - Final Construction Permit 11MF332 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF332

- Limits opacity to 20%
- Requires bagfilter control of ash silos
- Sets forth measures for minimizing fugitive dust emissions

Construction Permit requirement is revised from: "All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system." To: "All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system."

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control

equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: truck loading for disposal

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloader on silo A discharges directly into silo A. Therefore, there is not a separate source of emissions. The dry ash unloading on silo B discharges to a bagfilter which discharges inside the silo B building adjacent to a piperack, therefore, a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence. Quarterly inspections will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P204 – Ash Handling System and Ash Haul Road Ash Haul Road for Units 1, 2 and 3 (Ash and Scrubber Sludge Hauling)

The Unit 3 ash handling and processing system provides for transferring of ash from the Unit 3 boiler, baghouse hoppers, and ash collection locations in the scrubber building to an ash silo or the recycle ash tank for temporary storage before it is transported offsite for disposal or commercial sale. The boiler generates both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Flyash is pneumatically conveyed to the silo. Baghouses control PM emissions for the silo, day tank and dry ash unloading for commercial sale. Water and dustless unloaders control PM for the ash unloading operations for disposal. Magnesium chloride is applied to the unpaved portion of the ash haul road, as necessary, to control PM emissions.

Applicable Requirements - Final Construction Permit 12MF322(3) was issued for these activities. Applicable requirements are as follows.

Construction Permit 12MF322(3)

- Limits opacity to 20%

- Sets forth measures for minimizing fugitive dust emissions
(Note: Construction Permit Condition 3. States "Ash deposited in trucks for transport to disposal areas shall be sufficiently wet to maintain a moisture content greater than 12% and/or a control of visible emissions equal to that of an enclosed cargo box originally permitted." The Division believes requiring a specific moisture content is not practical. In addition, it is not practical to attempt to compare current visible emissions to the now removed cargo box. This condition is therefore revised as follows: "Ash deposited in trucks for transport to disposal areas shall be sufficiently moist to minimize fugitive emissions." This is consistent with minimization measures set forth in the Construction Permit 11MF332 for Units 1 & 2 ash handling.

PSD Permit

- Requires magnesium chloride to be used on the ash haul road according to manufacturer's specifications

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Not applicable to fugitive emission sources: truck loading for disposal and haul roads.

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloading baghouse is located inside a building, therefore a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. A quarterly inspection will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P205 – Staging/Landfilling

Wet and dry waste products are hauled to the staging/landfilling area, where they are unloaded. The staged wastes are then subsequently loaded in a truck for final disposal at Trapper Mine. The staging/landfilling activities are considered to have negligible emissions.

Applicable Requirements - Final Construction Permit 11MF994(F) was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF994(F)

- Sets forth a Particulate Emissions Control Plan
(Note: The Construction Permit indicates that Mining activities are subject to the 20% opacity guideline, under Regulation No. 1. This activity is not “mining,” but consists of construction (land clearing and leveling) and storage and handling of materials, which are also subject to the 20% opacity guideline. The permit language is revised to delete the reference to mining activities. The 20% is a guideline, as stated in Regulation No. 1 and its Statement of Basis and Purpose. The regulation shifted the use of opacity observations from an enforceable standard for area sources to a guideline in determining when the adequacy of applied control methods should be reviewed. U.S. EPA Method 9 readings are not required for these sources.)

Other

The Construction Permit does not specifically limit the amount of waste processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - A quarterly inspection will be performed to ensure PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P206 - Soda Ash Addition System

This system was for addition of soda ash to coal for Boiler Units #1 and #2. Due to the Consent Decree changes to the scrubber system, the soda ash addition system has been dismantled and is not longer included in this operating permit.

P401 – Unit 1 Cooling Tower

P402 – Unit 2 Cooling Tower

The cooling towers are used to dissipate waste heat from the boilers circulating water system. Pollutants expected to be emitted include PM and small quantities of chloroform produced by the introduction of chlorine in the recirculating cooling tower water to control biological growth. The cooling towers were not permitted at the time of the initial Operating Permit application submittal. The application documents for a construction permit were submitted and Initial construction permits were subsequently issued.

Applicable Requirements - Initial Construction Permits 98MF0141 and 96MF195 were issued for these sources. The source has demonstrated compliance under the provisions of Regulation No. 3, Part B, Section IV.H for initial approval construction permit 98MF0141 but not yet received a final approval construction permit. Under the provisions of Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit.

Construction Permits 98MF0141 and 96MF195

- Limit the design and maximum circulating water rates.
- Limit the total dissolved solids content of the water.
- Limit the drift loss and set forth schedules for retrofitting drift eliminators (at the time of Construction Permit issuance, the cooling towers equipped with older style drift eliminators. New, more efficient drift eliminators are considered to represent "BACT" for cooling towers, and the schedule was developed to implement the new style drift eliminators.) The Construction Permits require progress reports by March 31 of the following year. The Operating Permit requires reports by April 30, to be consistent with APEN reporting requirements. (*Note: Construction of the new drift eliminators is completed, therefore the schedule is not included in this operating permit.*)
- Limits PM, PM₁₀, and VOC emissions

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

Emission Factors - PM emissions are estimated using EPA factors. VOC emissions are estimated using factors from a report by Michelletti. A copy of the report is included in the Operating Permit application.

Monitoring Plan - Measurements of TDS will be made and recorded monthly.

Compliance Status - The applicant has submitted the documents needed to obtain a construction permit and permits were issued. The Division accepts the cooling towers are now in compliance.

Miscellaneous

Emission Factors - From time to time published emission factors and/or other emission estimating methods are changed based on new or improved data. A logical concern is what happens if the use of the new factors/methods in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors, equations, and/or other emission estimating methods included in the permit are considered to be fixed until changed by the permit. Obviously, emission factors dependent on the fuel sulfur content or heat content of the fuel can not be fixed and will vary with the test results. The method for determining the emissions is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, etc. and to notify the Division in writing of impacts on the permit requirements when there is a change. Upon notification, the Division will work with the permittee to address the situation. In addition, the Division will review the factors, etc. as appropriate during permit modifications and renewals.

APEN Reporting for Insignificant Activities - Some sources permitted under the issued Construction Permits are insignificant sources because the uncontrolled actual emissions for recent years are below APEN de minimis levels. (Note: Those sources with emissions below de minimis levels, but which are subject to an NSPS requirement are still subject to APEN reporting requirements.) These sources are listed in the Operating Permit as permitted sources, in the event emissions should increase above the de minimis level in the future.

Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

Based on the information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

Compliance Assurance Monitoring (CAM)

The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-controlled emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV:

None.

(The Title V application was deemed administratively complete prior to April 20, 1998.)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Craig Unit 1	)	Order No. 202-26-31
	)	
	)	

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

Exhibit MM: Tri-State, *General APEN- Form APCD-200* (Apr. 21, 2025)



General APEN – Form APCD-200

Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN form must be completed for both new and existing sources, including APEN updates. The Permit Application/Registration Checklist (Form APCD-100) must also be completed and submitted with this APEN form, unless specifically exempted. Incomplete applications will be rejected and will require re-submittal. *Your application will be rejected if it is filled out incorrectly, is missing information, or lacks payment for applicable fees. The re-submittal will require new payment for applicable fees.*

There may be a more specific APEN for your source (e.g. boiler, mining operations, engines, etc.). A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: 96OPMF155

AIRS ID Number: 081 / 0018 / 001

(Leave blank unless APCD has already assigned a permit # and AIRS ID)

Section 1 - Administrative Information

Company Name¹: Tri-State Generation and Transmission Association, Inc.

Site Name: Craig Station

Site Location: 2101 S. Ranney

Craig CO 81626

Site Location
County: Moffat

NAICS or SIC Code: 4911

Mailing Address:
(Include Zip Code) 1100 W. 116th Avenue

Westminster, CO

Contact Person: Brian Massengale

Phone Number: 303-254-3785

Portable Source
Home Base: NA

E-Mail Address²: brian.massengale@tristategt.org

¹ Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.

² Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

517882

Permit Number: 96OPMF155

AIRS ID Number: 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☐ NEW permit OR newly-reported emission source (check one below)

☐ STATIONARY source

☐ PORTABLE source

- OR -

☐ MODIFICATION to existing permit (check each box below that applies)

☐ Change fuel or equipment

☐ Change company name³

☐ Add point to existing permit

☐ Change permit limit

☐ Transfer of ownership⁴

☐ Other (describe below)

- OR -

☒ APEN submittal for update only (Note blank APENs will not be accepted)

- ADDITIONAL PERMIT ACTIONS -

☐ Limit Hazardous Air Pollutants (HAPs) with a federally-enforceable limit on Potential To Emit (PTE)

☐ APEN submittal for permit exempt/grandfathered source

Additional Info & Notes: Craig Station Unit 1 Boiler

³ For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.

⁴ For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.

Section 3 - General Information

General description of equipment and purpose: Electric Generation

Manufacturer: Babcock & Wilcox

Model No.: NB24157

Serial No.: NA

Company equipment Identification No.
(optional):

B001

For existing sources, operation began on:

1980

For new or reconstructed sources, the projected start-up date is:

NA

☒ Check this box if operating hours are 8,760 hours per year; if fewer, fill out the fields below:

Normal Hours of Source Operation: _____ hours/day _____ days/week _____ weeks/year

Seasonal use percentage: Dec-Feb: _____ Mar-May: _____ Jun-Aug: _____ Sep-Nov: _____

Permit Number: **96OPMF155**

AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Processing/Manufacturing Information & Material Use

☒ Check box if this information is not applicable to source or process

From what year is the actual annual amount? _____

	Description	Design Process Rate (Specify Units)	Actual Annual Amount (Specify Units)	Requested Annual Permit Limit ⁵ (Specify Units)
Material Consumption:				
Finished Product(s):				

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

Section 5 - Geographical/Stack Information

Geographical Coordinates (Latitude/Longitude or UTM)
13T 280,410 m E 4,482,335 m N

☐ Check box if the following information is not applicable to the source because emissions will not be emitted from a stack. If this is the case, the rest of this section may remain blank.

Operator Stack ID No.	Discharge Height Above Ground Level (Feet)	Temp. (°F)	Flow Rate (ACFM)	Velocity (ft/sec)
S001	600	117	1,838,406	62

Indicate the direction of the stack outlet: (check one)

- ☒ Upward
 ☐ Downward
 ☐ Upward with obstructing raincap
☐ Horizontal
 ☐ Other (describe): _____

Indicate the stack opening and size: (check one)

- ☒ Circular Interior stack diameter (inches): **300**
☐ Square/rectangle Interior stack width (inches): _____ Interior stack depth (inches): _____
☐ Other (describe): _____

Permit Number: **96OPMF155**AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 6 - Combustion Equipment & Fuel Consumption Information

☐ Check box if this information is not applicable to the source (e.g. there is no fuel-burning equipment associated with this emission source)

Design Input Rate (MMBTU/hr)	Actual Annual Fuel Use (Specify Units)	Requested Annual Permit Limit ⁵ (Specify Units)
4,318	956,258 tpy	3,900,000 tpy

From what year is the actual annual fuel use data? 2024

Indicate the type of fuel used⁶:

- ☐ Pipeline Natural Gas (assumed fuel heating value of 1,020 BTU/SCF)
- ☐ Field Natural Gas Heating value: _____ BTU/SCF
- ☐ Ultra Low Sulfur Diesel (assumed fuel heating value of 138,000 BTU/gallon)
- ☐ Propane (assumed fuel heating value of 2,300 BTU/SCF)
- ☒ Coal Heating value: 9,763 BTU/lb Ash content: 9.3% Sulfur content: 0.4%
- ☐ Other (describe): _____ Heating value (give units): _____

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

⁶ If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Section 7 - Criteria Pollutant Emissions Information

Attach all emission calculations and emission factor documentation to this APEN form.

Is any emission control equipment or practice used to reduce emissions? ☒ Yes ☐ No

If yes, describe the control equipment AND state the collection and control efficiencies:

Pollutant	Control Equipment Description	Collection Efficiency (% of total emissions captured by control equipment)	Control Efficiency (% reduction of captured emissions)
TSP (PM)	Baghouse		99.9
PM ₁₀	Baghouse		99.9
PM _{2.5}	Baghouse		99.9
SO _x	Wet Scrubber		93.7
NO _x	Low NOx Burner/Overfire Air		45-60
CO	None		
VOC	None		
Other:			

Permit Number: **96OPMF155**AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

2024From what year is the following reported *actual annual emissions* data?

Use the following table to report the criteria pollutant emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

Pollutant	Uncontrolled Emission Factor (Specify Units)	Emission Factor Source (AP-42, Mfg., etc.)	Actual Annual Emissions		Requested Annual Permit Emission Limit(s) ⁵	
			Uncontrolled (tons/year)	Controlled ⁷ (tons/year)	Uncontrolled (tons/year)	Controlled (tons/year)
TSP (PM)	0.0100 lb/MMBtu	2024 Stack Test, AP-42		93		NA
PM ₁₀	0.0092 lb/MMBtu	2024 Stack Test, AP-42		86		NA
PM _{2.5}	0.0053 lb/MMBtu	2024 Stack Test, AP-42		49		NA
SO _x	Measured	CEMS		335		NA
NO _x	Measured	CEMS		2,176.6		NA
CO	0.5 lb/ton	AP-42	239			NA
VOC	0.0002 lb/MMBtu	1999 Stack Test, AP-42	2			NA
Other:						

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

⁷ Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

Section 8 - Non-Criteria Pollutant Emissions Information

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year?

☒ Yes☐ No

If yes, use the following table to report the non-criteria pollutant (HAP) emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

CAS Number	Chemical Name	Overall Control Efficiency	Uncontrolled Emission Factor (Specify Units)	Emission Factor Source (AP-42, Mfg., etc.)	Uncontrolled Actual Emissions (lbs/year)	Controlled Actual Emissions ⁷ (lbs/year)
7782505 / 7440-02-0	Chlorine / Nickel		518 lb/TBtu / 1.4E-4 lb/MMBtu	2000 Stack Test / 2010 Test	10,168 / 2,748	
7440-47-3 / 75-09-2	Chromium / Methylene Chloride		2.08 E-4 lb/MMBtu / 18.9E-6 lb/TBtu	2010 Stack Test / EPRI	4,083 / 371	
57-12-5 / 7664-93-9	Cyanide / Sulfuric Acid		2.5 E-3 lb/ton / 7E-4 lb/MMBtu	AP-42 / 2009 Stack Test	2,391 / 13,070	
7647-01-0	Hydrogen Chloride		5.5 E-5 lb/MMBtu	2009 Stack Test	1,080	
7664-39-3	Hydrogen Fluoride		2.07 E-4 lb/MMBtu	2009 Stack Test	4,063	
7439-96-5	Manganese		3.67E-4 lb/MMBtu	2010 Stack Test	7,204	

⁷ Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

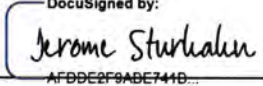
Permit Number: **96OPMF155**

AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 9 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct.

DocuSigned by:	
	4/21/2025
AFBDE2F9ADE741B...	
Signature of Legally Authorized Person (not a vendor or consultant)	Date
Jerome H. Sturhahn	Senior Vice President, General Counsel
Name (print)	Title

Check the appropriate box to request a copy of the:

- ☐ Draft permit prior to issuance
- ☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with \$242.00 to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

For more information or assistance, contact:

Small Business Assistance Program
cdphe_apcd_sbap@state.co.us

APCD Main Phone Number
(303) 692-3100

Make check payable to: Colorado Department of Public Health and Environment

Alternatively, payment can be provided online, by credit card or electronic check, via the [APCD Payment Portal](#).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

)
)
)
)

Order No. 202-26-31

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

Exhibit NN: Division, *Colorado Visibility and Regional Haze SIP for the Twelve
Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)

Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado

Colorado Air Pollution Control Division

Revised Regional Haze Plan

***Adopted by the Colorado Air Quality Control Commission on
December 15, 2016***

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Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

Regional Haze Plan	Approval Date
Original	12/21/2007
First Revision	12/19/2008
Second Revision	01/07/2011
Third Revision	11/20/2014
Fourth Revision	12/15/2016

Chapter 1 Overview

1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

“Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.”

The federal visibility regulations (40 CFR Part 51 Subpart P - Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to ‘natural conditions’ by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources. Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064, this plan is designed to meet the two requirements for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal. This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

Black Canyon of the Gunnison National Park

Eagles Nest Wilderness Area

Flat Tops Wilderness Area

Great Sand Dunes National Park

La Garita Wilderness Area

Maroon Bells-Snowmass Wilderness Area

Mesa Verde National Park

Mount Zirkel Wilderness Area

Rawah Wilderness Area

Rocky Mountain National Park

Weminuche Wilderness Area

West Elk Wilderness Area

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations



1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006. As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures.

This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

1.5 Reasonable Progress towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.¹ The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

¹ See <http://www.wrapair.org/forums/sp/docs.html>

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA's so called 'presumptive' emission limits for NO_x and SO₂, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state's conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination.

Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NO_x and SO₂ are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements. Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NO_x emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NO_x emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents. By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others. The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow. The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to "develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan." The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA's Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, "The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State....Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network." The federal agencies' monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1, and will be met by participating in the IMPROVE network.

Colorado's monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

To provide regional haze monitoring representing all visibility-protected federal Class I areas

3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
 - a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
 - b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
 - a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
 - b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
 - a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (<http://vista.cira.colostate.edu/improve/>) and VIEWS (<http://vista.cira.colostate.edu/views/>). Through participation in the IMPROVE network, Colorado will partially satisfy the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.
 - b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].
 - a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.
 - i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (<http://www.wrapedms.org/InventoryDesc.aspx>). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls
5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].
 - a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see Section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.
6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].
 - a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service.

In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management. The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical. The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations



Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

Figure 3-2 Colorado IMPROVE Monitoring Site Information

Mandatory Class I Federal Area	Operating Agency	IMPROVE Monitor	Elevation [ft]	Start Date
Great Sand Dunes National Park	NPS	GRSA1	8,215	5/4/1988
Mesa Verde National Park	NPS	MEVE1	7,142	3/5/1988
Mount Zirkel Wilderness	USFS	MOZI1	10,640	7/30/1994
Rawah Wilderness				
Rocky Mountain National Park	NPS	ROMO1	9,039	9/19/1990
Weminuche Wilderness	USFS	WEMI1	9,072	3/2/1988
Black Canyon of Gunnison NP				
La Garita Wilderness				
Eagles Nest Wilderness	USFS	WHRI1	11,214	7/17/2000
Flat Tops Wilderness				
Maroon Bells-Snowmass Wilderness				
West Elk Wilderness				

3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program² to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network.

² <http://vista.cira.colostate.edu/improve/>

Colorado will continue to work with EPA in refining monitoring strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements. Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network. As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v). The State will use the Fire Emissions Tracking System (FETS)³ to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations.

The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)⁴ or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

³ <http://www.wrapfets.org/>

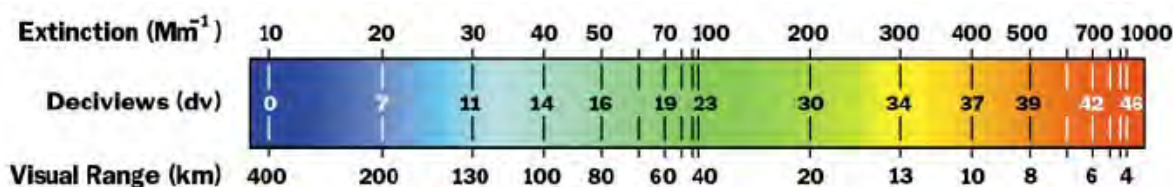
⁴ <http://pah.cert.ucr.edu/aqm/308/>

Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters ($1/\text{Mm}$ or Mm^{-1}). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in *the deciview (dv)* unit [(40 CFR 51.308(d)(2))]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction (Mm^{-1}), haze index (dv) and visual range (km) are



indicated by the following scale:

4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii))]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the “Haze Index”, which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado’s twelve Class I areas. The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)

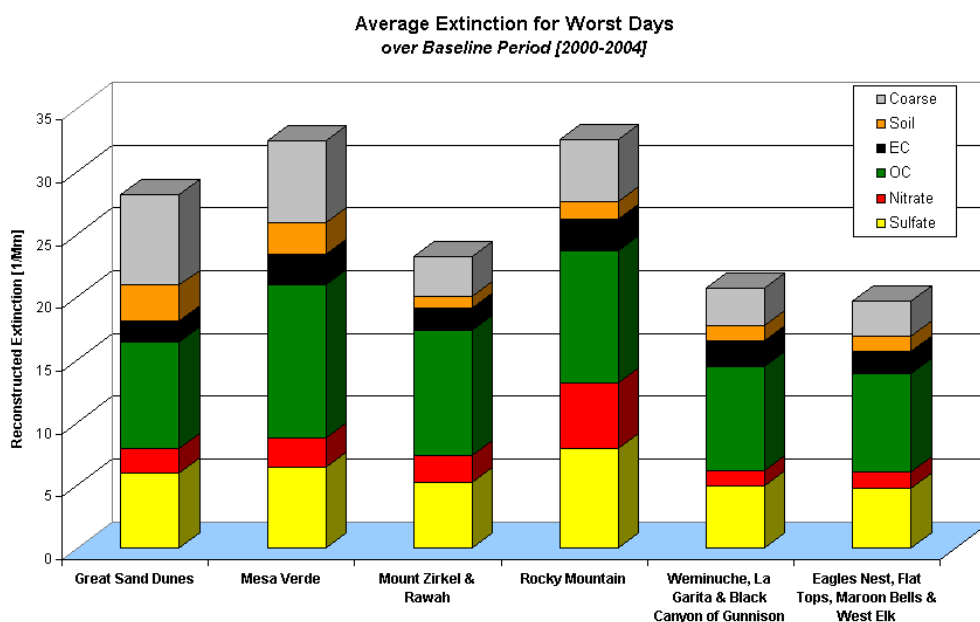
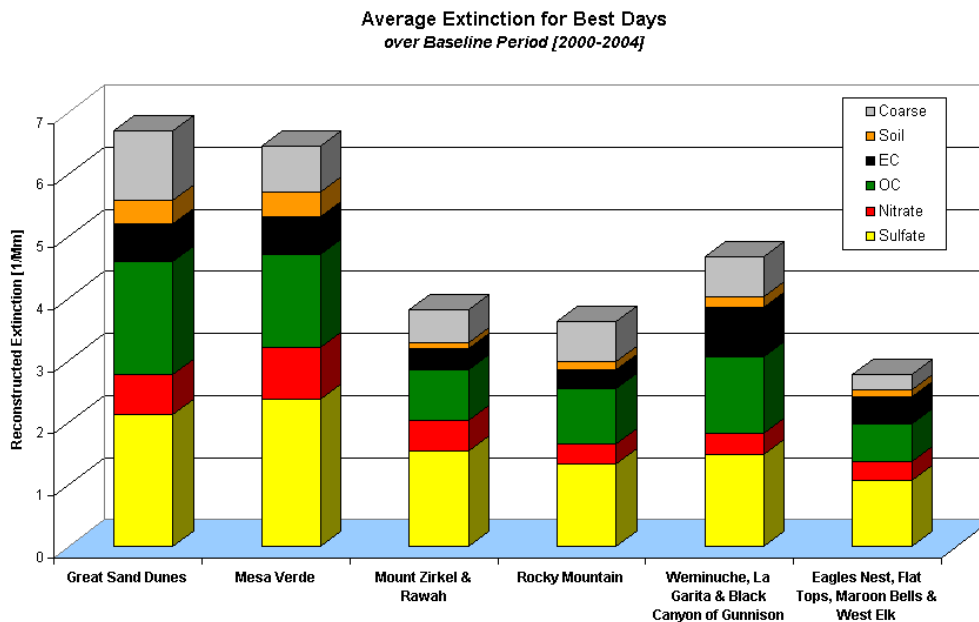


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)]. Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

Figure 4-3: 2064 Natural Conditions Goal for Worst Days

Mandatory Class I Federal Areas in Colorado	2064 Natural Conditions for 20% Worst Days [Deciview]
Great Sand Dunes National Park & Preserve	6.66
Mesa Verde National Park	6.81
Mount Zirkel & Rawah Wilderness Areas	6.08
Rocky Mountain National Park	7.15
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	6.21
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	6.06

4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B))]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column “2018 Uniform Progress Goal (Deciview)”.

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

$$URP = [Baseline\ Condition - Natural\ Condition] / 60\ years$$

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

$$2018\ UPG = [URP] \times [14\ years]$$

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions. More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado’s twelve Class I areas. This calculation is consistent with EPA’s *Guidance for Setting Reasonable Progress Goals under the Regional Haze Rule* (June 1, 2007). For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day’s baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area

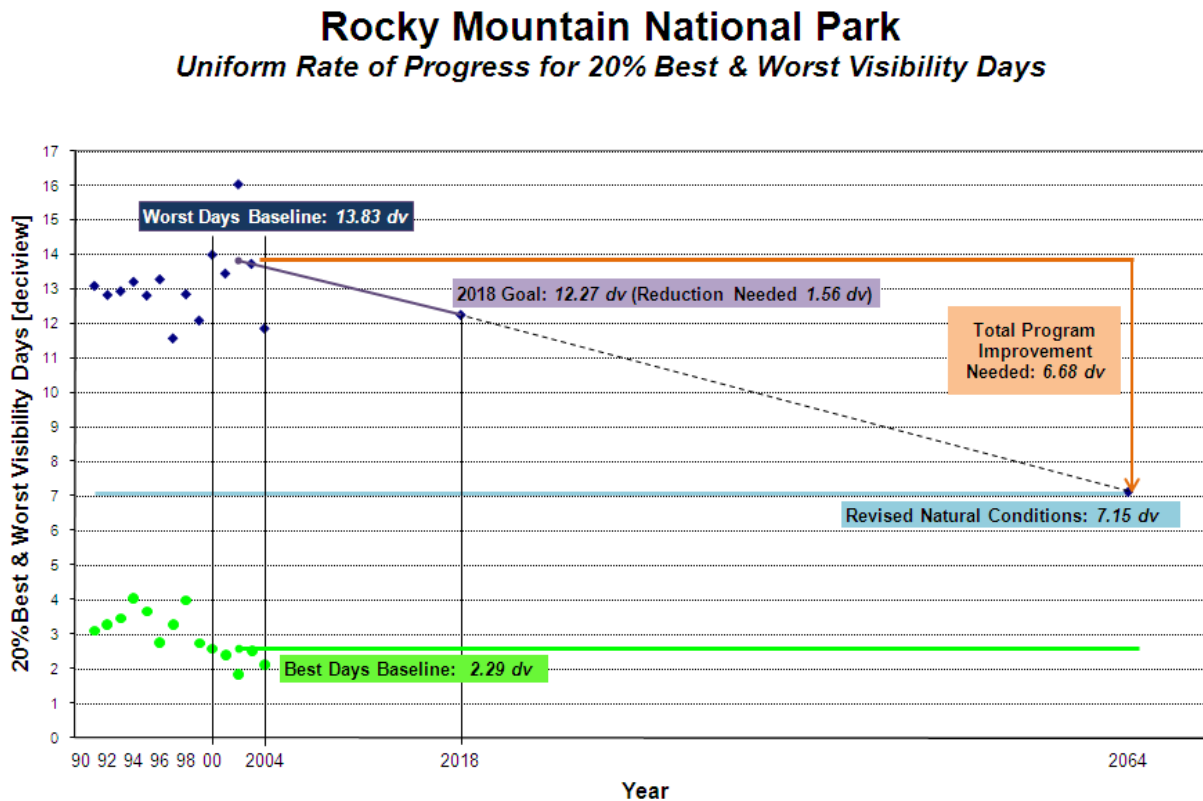
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

Mandatory Class I Federal Area	20% Worst Days					20% Best Days
	Baseline Condition [Deciview]	2018 Uniform Progress Goal [Deciview]	2018 Goal Delta [Deciview]	2064 Natural Conditions [deciview]	2064 Delta (Baseline - 2064 NC) [deciview]	Best Days Baseline Condition [Deciview]
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	13.83	12.27	1.56	7.15	6.68	2.29
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	6.06	3.55	0.70

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best day's baseline.

Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park



Chapter 5 Sources of Impairment in Colorado

5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days. Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO₂ & NO_x and other secondary particulate forming pollutants such as VOC and NH₃.

Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO₂), nitrogen oxides (NO_x), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM_{2.5}), coarse particulate (PM_{2.5} to PM₁₀), and ammonia (NH₃). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: <http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx> and a summary description of the inventory is found in the Emission Inventory TSD. Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods.

For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

Figure 5-1 Colorado SO₂ Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide SO ₂ Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	97,984	44,062	-55%
Area	6,533	7,644	17%
On-Road Mobile	4,389	677	-85%
Off-Road Mobile	3,015	754	-75%
WRAP Area O&G	118	11	-91%
Road Dust	4	6	34%
Fugitive Dust	6	5	-13%
Anthro Fire	108	91	-15%
Natural Fire	3,335	3,335	0%
Biogenic	-	-	-
Total:	115,492	56,585	-51%

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO₂ emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as ‘natural’ these represent only 3% of the statewide inventory. A 51% statewide reduction in SO₂ emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

Figure 5-2 Colorado NO_x Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide NO _x Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	405,507	282,010	-30%

Nitrogen oxides (NO_x) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources.

Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

Figure 5-3 Colorado VOC Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide VOC Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	91,750	77,312	-16%
Area	99,191	136,032	37%
On-Road Mobile	100,860	41,489	-59%
Off-Road Mobile	38,401	24,684	-36%
WRAP Area O&G	27,259	43,639	60%
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	915	666	-27%
Natural Fire	20,404	20,404	0%
Biogenic	804,777	804,777	0%
Total:	1,183,557	1,149,002	-3%

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory - 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide POA Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	17	3	-83%
Area	8,432	8,738	4%
On-Road Mobile	1,280	1,288	1%
Off-Road Mobile	1,286	843	-34%
WRAP Area O&G	-	-	-
Road Dust	102	135	33%
Fugitive Dust	777	677	-13%
Anthro Fire	850	621	-27%
Natural Fire	30,581	30,581	0%
Biogenic	-	-	-
Total:	43,325	42,886	-1%

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory - 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide EC Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	-	-	-
Area	1,264	1,325	5%
On-Road Mobile	1,448	408	-72%
Off-Road Mobile	3,175	1,344	-58%
WRAP Area O&G	-	-	-
Road Dust	9	11	33%
Fugitive Dust	53	46	-13%
Anthro Fire	92	74	-20%
Natural Fire	6,337	6,337	0%
Biogenic	-	-	-
Total:	12,377	9,545	-23%

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

Figure 5-6 Colorado Soil (PM Fine) Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide Soil (fine PM) Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	6	85	1404%
Area	4,170	4,311	3%
On-Road Mobile	-	-	-
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	1,082	1,435	33%
Fugitive Dust	13,401	11,679	-13%
Windblown Dust	15,105	15,105	0%
Anthro Fire	253	169	-33%
Natural Fire	1,948	1,948	0%
Biogenic	-	-	-
Total:	35,964	34,732	-3%

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide Coarse PM Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	21,096	26,828	27%
Area	1,363	1,388	2%
On-Road Mobile	794	917	15%
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	8,930	11,826	32%
Fugitive Dust	67,642	67,910	0%
Windblown Dust	135,945	135,945	0%
Anthro Fire	51	32	-37%
Natural Fire	5,973	5,973	0%
Biogenic	-	-	-
Total:	241,794	250,818	4%

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

Figure 5-8 Colorado Ammonia (NH₃) Emission Inventory - 2002 & 2018

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide Ammonia Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	453	571	26%
Area	60,771	60,791	0%
On-Road Mobile	4,317	5,894	37%
Off-Road Mobile	43	60	38%
WRAP Area O&G	-	-	-
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	137	95	-31%
Natural Fire	1,965	1,965	0%
Biogenic	-	-	-
Total:	67,686	69,375	2%

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

Chapter 6 Best Available Retrofit Technology

6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. See 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977. Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation Number 3, Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: <http://www.cdphe.state.co.us/ap/RegionalHazeBART.html>.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO₂, NO_x and particulate matter.

2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.
3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1.

Table 6 - 1 Results of Subject-to-BART Modeling

Modeled BART-Eligible Source	Division Modeling (98th percentile delta-deciview value)	Division Approved Refined Modeling from Source Operator (98 th percentile delta-deciview value)	Contribution Threshold (deciviews)	Impact Equal to or Greater Than Contribution Threshold?
CEMEX - Lyons Cement Kiln & Dryer	1.533		0.5	Yes
CENC (Trigen-Colorado) Units 4 & 5	1.255		0.5	Yes
Cherokee Station - Unit 4	1.460		0.5	Yes
Comanche Station - Units 1 and 2	0.701		0.5	Yes
Craig Station - Units 1 & 2	2.689		0.5	Yes
Hayden Station - Units 1 & 2	2.538		0.5	Yes
Lamar Light & Power - Unit 6	0.064		0.5	No
Martin Drake Power Plant - Units 5, 6 & 7	1.041		0.5	Yes
Pawnee Station - Unit 1	1.189		0.5	Yes
Ray D. Nixon Power Plant - Unit 1	0.570	0.481	0.5	No
Suncor Denver Refinery	0.239		0.5	No
Valmont Station - Unit 5	1.591		0.5	Yes
Notes:				
1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.				
2. Source operator modeling results are shown only if modeling has been approved by Division.				
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.				
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).				
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.				
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO ₂ .				
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.				

Of the BART-eligible sources listed, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO ₂ Control Type	SO ₂ Emission Limit	Assumed ** Particulate Control and Emission Limit
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Catalytic Reduction System	***	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO ₂ Control Type	SO ₂ Emission Limit	Assumed ** Particulate Control and Emission Limit
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 *or* cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources ^{5, 6, 7}					
Emission Unit	NOx Control Type	NOx Emission Limit	SO₂ Control Type	SO₂ Emission Limit	Particulate Control and Emission Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (rolling 12 month average) 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the table is not a requirement.

⁵ Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

⁶ 500 tpy NOx will be reserved from Cherokee station for netting or offsets.

⁷ 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

6.4.1 The State's Consideration of BART Factors

In identifying a level of control as BART, States are required by Section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

- (1) The costs of compliance,
- (2) The energy and non-air quality environmental impacts of compliance,
- (3) Any existing pollution control technology in use at the source,
- (4) The remaining useful life of the source, and
- (5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. See, Regulation Number 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NO_x controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

6.4.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO₂ and NO_x control equipment to upgrade analyses of existing SO₂ controls. The cost for each unit is summarized and the state's consideration of this factor for each source is presented in detail in Appendix C.

6.4.1.2 The energy and non-air quality environmental impacts of compliance.

This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO₂, as further described.

6.4.1.3 Any existing pollution control technology in use at the source. The state has taken into consideration the existing PM, SO₂ and NO_x pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that “a well-performing baghouse represents the best performance for PM” see 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO₂ controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulfurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. See 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NO_x controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NO_x controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

6.4.1.4 The remaining useful life of the source. None of Colorado’s BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state’s BART determinations.

6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented and in Appendix C.

6.4.2 SIP Requirements from EPA’s Regional Haze Rule

The following section includes information addressing the SIP elements contained in EPA’s Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

- (i) A list of all BART-eligible sources within the State.

Table 6 - 3 lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division’s source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado’s BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the “cause or contribute” thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Cemex - Lyons Kiln	Cemex	Portland Cement	<1977	Subject-to-BART
Cemex - Lyons Dryer	Cemex	Portland Cement	<1977	Subject-to-BART
CENC Unit 4	Colorado Energy Nations Company (CENC)	360 MMBtu/hr	1975	Subject-to-BART
CENC Unit 5	CENC	650 MMBtu/hr	1979	Subject-to-BART
Cherokee Unit 4	Public Service Company of Colorado (PSCO)	350 MW	1968	Subject-to-BART
Comanche Unit 1	PSCO	350 MW	1973	Subject-to-BART
Comanche Unit 2	PSCO	350 MW	1976	Subject-to-BART

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Craig Unit 1	Tri-State Generation and Transmission, Inc.	446 MW	1979	Subject-to-BART
Craig Unit 2	Tri-State	446 MW	1979	Subject-to-BART
Hayden Unit 1	PSCO	190 MW	1965	Subject-to-BART
Hayden Unit 2	PSCO	275 MW	1976	Subject-to-BART
Martin Drake Unit 5	Colorado Springs Utilities (CSU)	55 MW	1962	Subject-to-BART
Martin Drake Unit 6	CSU	85 MW	1968	Subject-to-BART
Martin Drake Unit 7	CSU	145 MW	1974	Subject-to-BART
Pawnee Unit 1	PSCO	500 MW	1981	BART Alternative
Valmont Unit 5	PSCO	188 MW	1964	Subject-to-BART
Denver Steam Unit 1	PSCO	Steam only 210 MMBtu/hr	1972	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Denver Steam Unit 2	PSCO	Steam only 243 MMBtu/hr	1974	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Holcim Kiln	Holcim	Portland Cement	<1977	Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions.
Lamar Utilities	City of Lamar	25 MW	1972	Plant will be shut down; so will no longer be subject.
Oregon Steel	Oregon Steel	Steel Mfg.	<1977	Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions.
Ray Nixon Unit 1	CSU	227 MW	1980	Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact)
Roche	Roche	Pharmaceutic al Mfg.	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO
Suncor/Valero	Suncor	Refinery	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO

- (ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

- (iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

- (iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail.

- (v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation Number 3, Part F, Section VI.

- (vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation Number 3, Part F, Section VII.

6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

- (1) The costs of compliance,
- (2) The energy and non-air quality environmental impacts of compliance,
- (3) Any existing pollution control technology in use at the source,
- (4) The remaining useful life of the source, and
- (5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.⁸ The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.⁹

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO₂ and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO₂ and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NO_x controls on BART electric generating units, for reasons described, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NO_x add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO₂ emissions, there are currently ten lime spray dryer (LSD) SO₂ control systems operating at electric generating units in Colorado.¹⁰ There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO₂ emissions in the state and other non-air quality considerations.

⁸ The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. See 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. See, e.g., *id.* at 39108, 39131 and 39158.

⁹ See, e.g., 70 Fed. Reg. at 39170.

¹⁰ EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, and Valmont Unit 5.

Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.¹¹ The Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO₂ emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NO_x emissions, post-combustion controls for NO_x are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NO_x emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NO_x emissions.

¹¹ In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. See 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id.* See also, 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NO_x Limits for Electric Generating Units* and *Technical Support Document for BART NO_x Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO₂ Limits for Electric Generating Units*, Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

In assessing and determining appropriate NO_x BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.¹² In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (e.g., expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NO_x) from the atmosphere, or \$/ton of NO_x removed); and, (ii) visibility improvement expected from the control options analyzed (e.g., expressed as visibility improvement in delta deciview (Δ dv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NO_x post-combustion control options to aid in the assessment and determinations for BART - a \$/ton of NO_x removed cap, and two minimum applicable Δ dv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows. For the highest-performing NO_x post-combustion control options (i.e., SCR systems for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x post-combustion control options (e.g., SNCR technologies for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis. The cost criteria presented is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the \$5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.¹³

¹² See 70 Fed. Reg. at 39170 and 39137.

¹³ Air Quality Control Commission Regulation Number 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

In that case, a \$5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.¹⁴ The \$5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of \$5,000/ton (and lower), while control costs for Colorado BACT can be in the range of \$5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NO_x controls, *i.e.*, SCR, has the ability to provide significant NO_x reductions, but also has initial capital dollar requirements that can approach or exceed \$100 million per unit.¹⁵ The lesser-performing post-combustion NO_x controls, *e.g.*, SNCR, reduce less NO_x on a percentage basis, but also have substantially lower initial capital requirements, generally less than \$10 million.¹⁶

The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NO_x controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δ_{dv} or greater of visibility improvement at the primary affected Class I Area.¹⁷ For the lesser-performing add-on NO_x controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δ_{dv} or greater of visibility improvement at the primary affected Class I Area. Employing the foregoing guidance criteria for post-combustion NO_x controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

¹⁴ The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

¹⁵ See, *e.g.*, Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, \$83MM; Public Service of Colorado, Hayden Unit #2, \$72MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$210MM.

¹⁶ See, *e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, \$1.4MM; Public Service Company of Colorado, Hayden Unit #2, \$4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$13.1MM

¹⁷ The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δ_{dv} are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. See, Air Quality Control Commission Regulation Number 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δ_{dv} or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

6.4.3.1 BART Determination for CEMEX's Lyons Cement Plant

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO₂ and NO_x emissions. The raw material dryer emits minor amounts of SO₂ and NO_x; in 2008 Cemex reported SO₂ and NO_x emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000°F) for reducing NO_x to elemental Nitrogen. Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO₂ emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th percentile visibility impact from the kiln is 0.76 Δdv . Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv . Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO₂ emission limitation is 36.7 tpy and the BART NO_x emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

SO₂ BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO₂ emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

Cemex Lyons -Kiln				
SO ₂ Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO ₂ Emissions (lbs/hr)	Annual Controlled SO ₂ Emissions (tpy)	Annual Controlled SO ₂ Emissions (lb/ton of Clinker)
Baseline SO ₂ Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	18.9	71.3	0.30
Fuel Substitution (coal with TDF)	40%	15.2	57.0	0.24
Dry Sorbent Injection	50%	12.6	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel - the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. See, Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. CEMEX's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO₂ emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
SO ₂ Control Technology	SO ₂ Emission Reduction (tons/yr)	Annualized Cost (\$/yr)	Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline SO ₂ Emissions	-			
Lime Addition to Kiln Feed	23.8	\$3,640,178	\$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	\$172,179	\$4,531	\$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	\$2,529,018	\$29,579	\$49,618

The following table lists the projected visibility improvements for SO₂ controls:

Cemex Lyons - Kiln		
SO ₂ Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max)	0.760	
Baseline (95 tpy)*	0.731	-
Lime Addition to Kiln Feed (71.3 tpy)*	0.727	0.033
Fuel Substitution (57 tpy)*	0.725	0.034
Dry Sorbent Injection (47.5 tpy)*	0.725	0.036
Wet Lime Scrubbing (9.5 tpy)*	0.720	0.040

* Visibility impacts rescaled from original BART modeling

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO₂ emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO₂ emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO₂ per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO₂ control. Additional SO₂ scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

SO₂ BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO₂ BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NO_x BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NO_x burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NO_x emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes “available” control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

Cemex Lyons - Kiln				
NO _x Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NO _x Emissions (lbs/hr)	Annual Controlled NO _x Emissions (tpy)	Annual Controlled NO _x Emissions (lb/ton of Clinker)
Baseline NO _x Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel - the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. See, Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. CEMEX's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	(\$/yr)	(\$/ton)	(\$/ton)
Baseline NOx Emissions	-			
Water Injection	122.3	\$43,598	\$356	-
Coal w/TDF	174.7	\$172,179	\$986	\$2,453
Indirect Firing with LNB	349.4	\$710,750	\$2,034	\$3,083
SNCR (45.0% control)	786.2	\$1,636,636	\$2,082	\$2,120
SNCR (48.4% control)	846.1	\$1,636,636	\$1,934	\$1,864
SNCR w/LNB (55.0% control w/uncertainty)	960.9	\$1,686,395	\$1,755	\$434

The following table lists the projected visibility improvements for NO_x controls for the kiln:

Control Method	98th Percentile Impact (Δ dv)	98th Percentile Improvement (from 24-hr Max) (Δ dv)
24-hr Maximum ($\approx$ 656.9 lbs/hr))	0.760	
Revised Baseline ($\approx$ 464.3 lbs/hr)*	0.572	0.188
Original Baseline ($\approx$ 446.8 lbs/hr)*	0.555	0.205
Water Injection ($\approx$ 431.8 lbs/hr)*	0.540	0.220
Firing TDF ($\approx$ 417.9 lbs/hr)*	0.526	0.234
Indirect Firing with LNB ($\approx$ 371.4 lbs/hr)*	0.481	0.279
Original BART Limit - SNCR ($\approx$ 268.0 lbs/hr)	0.380	0.380
Proposed BART Limit (30-day) - SNCR ($\approx$ 255.3 lbs/hr)**	0.368	0.392
Proposed BART Limit (annual) - SNCR ($\approx$ 239.0 lbs/hr)**	0.352	0.408
SNCR w/LNB ($\approx$ 208.9 lbs/hr)**	0.322	0.438

The Cemex - Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system ($>1500^{\circ}\text{F}$) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NO_x control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NO_x emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NO_x control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NO_x are:

255.3 pounds per hour (30-day rolling average) and
901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NO_x reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δ dv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

NO_x BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NO_x BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its “NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado” Submittal provided on November 16, 2009, as well as additional information upon the Division’s request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

SO₂ BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and SO₂ emission management were determined to be technically feasible for reducing SO₂ emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO₂ emissions management uses a variety of options to reduce SO₂ emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak SO₂ limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 4 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SO ₂ Emissions Management	1.0	\$44,299	\$43,690
DSI - Trona	468.0	\$1,766,000	\$3,774

CENC Boiler 5 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SO ₂ Emissions Management	0.8	\$65,882	\$78,095
DSI - Trona	844.0	\$2,094,000	\$2,482

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

SO ₂ Control Method	CENC - Boiler 4		CENC - Boiler 5	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.90		0.98	
DSI - Trona (annual avg.)	0.26	0.08	0.29	0.13

SO₂ emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO₂ reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO₂ BART is the following SO₂ emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)

CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for CENC - Boilers 4 and 5

Low NO_x burners (LNB), LNB plus separated overfired air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NO_x emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 4 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	0	\$0
LNB	59.9	\$193,433	\$3,227
SNCR	179.8	\$694,046	\$3,860
LNB+SOFA	209.8	\$678,305	\$3,234
LNB+SOFA + SNCR	368.0	\$1,372,351	\$3,729
SCR	515.4	\$4,201,038	\$8,150

CENC Boiler 5 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
LNB	48.4	\$249,858	\$5,166
LNB+SOFA	127.3	\$815,829	\$6,383
SNCR	207.3	\$923,996	\$4,458
LNB+SOFA + SNCR	353.7	\$1,739,825	\$4,918
SCR	550.0	\$6,469,610	\$11,764

The energy and non-air quality impacts of the alternatives are as follows:

- LNB - not significant
- LNB + SOFA - may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR - increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	CENC - Boiler 4		CENC - Boiler 5	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	NOx l Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Maximum (3-yr)	0.67		0.66	
LNB (annual avg.)	0.45	0.05	0.30	0.17
SNCR (annual avg.)	0.35	0.07	0.24	0.21
LNB + SOFA (annual avg.)	0.32	0.08	0.24	0.21
LNB + SOFA + SNCR (annual avg.)	0.19	0.12	0.17	0.26
SCR	0.07	0.18	0.07	0.31

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NO_x BART for Boiler 5 is the following NO_x emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NO_x burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed in Section 6.4.3.

- Boiler 5: \$4,918 per ton NO_x removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in Section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

SO₂ BART Determination for Comanche - Units 1 and 2

Semi-Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the SO₂ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO₂ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO₂ removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* - PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO₂ removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.

- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO₂ emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO₂ removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

SO ₂ Control Method	Comanche - Unit 1		Comanche - Unit 2	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.75		0.74	
Semi-Dry FGD (LSD) (annual avg.)	0.12	0.35	0.12	0.33
Semi-Dry FGD (LSD) (annual avg.)	0.08	0.37	0.08	0.36

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO₂ emission rates are BART:

- Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
 0.10 lb/MMBtu (combined annual average for units 1 & 2)
- Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
 0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO₂ limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

Particulate Matter BART Determination for Comanche - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NO_x emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Comanche Unit 1 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	445.6	\$1,624,100	\$3,644
SCR	770.4	\$12,265,014	\$15,290

Comanche Unit 2 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SCR	1,480	\$14,650,885	\$9,900

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR - increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NO _x Control Method	Comanche - Unit 1		Comanche - Unit 2	
	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (1-yr) using new LNBs	0.20		0.20	
SNCR (annual avg.)	0.10	0.11	Not Feasible	-
SCR (annual avg.)	0.07	0.14	0.07	0.17

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NO_x BART is the following existing NO_x emission rates:

Comanche Unit 1:	0.20 lb/MMBtu (30-day rolling average)
	0.15 lb/MMBtu (combined annual average for units 1 & 2)
Comanche Unit 2:	0.20 lb/MMBtu (30-day rolling average)
	0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NO_x burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO₂ BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings*: Tri-State determined that installation of perforated trays, as described, accomplished the same objective.
- *Installation of perforated trays*: Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives*: Organic acid additives were considered but not selected for the following reasons:
 1. Dibasic Acid (DBA) has not been tested at the very low inlet SO₂ concentrations seen at Craig Units 1 and 2.
 2. DBA could cause changes in sulfite oxidation with impacts on SO₂ removal and solids settling and dewatering characteristics.
 3. Installation of the perforated plate tray accomplished the same objective of increased SO₂ removal.
- *Improve or upgrade scrubber auxiliary equipment*: 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
 1. Two vertical ball mills were installed for additional limestone processing capability for increased SO₂ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO₂ removal rates.
 2. Forced oxidation within the SO₂ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
 3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
 5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
 6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO₂ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
 7. Instrumentation and controls were modified to support all of the new equipment.
- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO₂ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO₂ limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO ₂ Control Method	Craig - Unit 1		Craig - Unit 2	
	SO ₂ Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO₂ BART is the following SO₂ emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO₂ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NO_x BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NO_x emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	779	\$3,797,000	\$4,877
SCR	4,048	\$25,036,709	\$6,184

Craig Unit 2 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	806	\$3,797,000	\$4,712
SCR	3,975	\$25,036,709	\$6,298

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig - Unit 1		Craig - Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.08	0.94

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMBtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements.

- Unit 1: \$6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: \$6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NO_x emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1.

This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station -related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the hearing 2014 record. In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): The first table assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table, an assumed amortization period of eight years of operation¹⁸ is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected¹⁹.

¹⁸ Operation period begins calendar year 2018 (December 31, 2017).

¹⁹ EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Craig Unit 1 - NO _x Cost Comparisons (assuming four years, four months of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	779	\$6,172,522	\$7,928
SCR	4,048	\$64,106,699	\$15,835

Craig Unit 1 - NO _x Cost Comparisons (assuming eight years of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	779	\$4,755,842	\$6,109
SCR	4,048	\$41,476,535	\$10,245

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NO_x emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

Or;

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NO_x emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NO_x emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NO_x limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NO_x reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 *or* cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023.

In the case of a conversion to natural-gas firing, a 30-day rolling average NO_x emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NO_x emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NO_x limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, including substantial cost information for NO_x controls, can be found in Appendix C.

6.4.3.5 BART Determination for Public Service Company's Hayden Station

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

SO₂ BART Determination for Hayden - Units 1 and 2

Semi-Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the SO₂ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO₂ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional SO₂ removal in the dry scrubbing systems present at Hayden Station.

- *Increase the pulverization level of sorbent* - PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO₂ removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO₂ emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Semi-Dry FGD Upgrade - Additional Equipment and Maintenance	61	\$141,150	\$2,317
Additional Scrubber Module	488	\$4,142,538	\$8,490

Hayden Unit 2 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Semi-Dry FGD Upgrade - Additional Equipment and Maintenance	39	\$141,150	\$3,626
Additional Scrubber Module	589	\$4,808,896	\$8,164

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Hayden - Unit 1		Hayden - Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Maximum (3-yr)	0.34		0.40	
Existing Semi-Dry FGD (LSD) (annual avg.)	0.16	0.09	0.16	0.18
Semi-Dry FGD Upgrade (annual avg.)	0.13	0.10	0.13	0.21
Additional Scrubber Module (annual avg.)	0.07	0.14	0.07	0.26

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NO_x emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
LNB	1,391	\$572,010	\$411
SNCR	1,391	\$1,353,500	\$973
SCR	3,120	\$10,560,612	\$3,385

Hayden Unit 2 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
LNB	1,303	\$992,729	\$762
SNCR	1,610	\$1,893,258	\$1,176
SCR	3,032	\$12,321,491	\$4,064

The energy and non-air quality impacts of the alternatives are as follows:

- LNB - not significant
- SNCR and SCR - increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NO _x Control Method	Hayden - Unit 1		Hayden - Unit 2	
	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.61		0.37	
LNB (annual avg.)	0.26	0.69	0.21	0.40
SNCR (annual avg.)	0.26	0.69	0.18	0.48
SCR (annual avg.)	0.07	1.12	0.06	0.85

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NO_x BART is the following NO_x emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented.

- Unit 1: \$3,385 per ton NO_x removed; 1.12 deciview of improvement
- Unit 2: \$4,064 per ton NO_x removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NO_x emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NO_x and SO₂ Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

SO₂ BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO₂ emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts.

Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
DSI	762	\$1,340,663	\$1,760

Drake Unit 6 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
DSI	1,671	\$2,910,287	\$1,741
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	2,284	\$6,186,854	\$2,709
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	2,368	\$6,647,835	\$2,808
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	2,507	\$7,452,788	\$2,973

Drake Unit 7 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
DSI	2,657	\$3,723,826	\$1,405
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	3,632	\$8,216,863	\$2,263
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	3,764	\$8,829,321	\$2,345
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	3,986	\$9,898,382	\$2,483

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD - less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO ₂ Control Method	Drake - Unit 5		Drake - Unit 6		Drake - Unit 7	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.94		1.00		0.99	
DSI (annual avg.)	0.25	0.12	0.33	0.18	0.33	0.29
Dry FGD (LSD) (annual avg.)	Not feasible		0.12	0.24	0.12	0.39
Dry FGD (LSD) (annual avg.)	Not feasible		0.07	0.26	0.07	0.41

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO₂ BART for Unit 5 is the following SO₂ emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: \$1,760 per ton SO₂ removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO₂ BART for Unit 6 and Unit 7 is the following SO₂ emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO₂ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: \$2,808 per ton SO₂ removed; 0.24 deciview of improvement
- Unit 7: \$2,345 per ton SO₂ removed; 0.39 deciview of improvement

Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM₁₀) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for Martin Drake - Units 5, 6 and 7

Ultra low NO_x burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NO_x emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - NO _x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Overfired air (OFA)	154	\$141,844	\$923
Ultra-low NO _x burners (ULNBs)	200	\$147,000	\$736
ULNBs + OFA	215	\$288,844	\$1,342
Selective Non-Catalytic Reduction (SNCR)	231	\$1,011,324	\$4,387
ULNB/SCR layered approach	626	\$4,467,000	\$7,133
Selective Catalytic Reduction (SCR)	626	\$4,580,000	\$7,314

Drake Unit 6 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Overfired air (OFA)	283	\$104,951	\$371
Selective Non-Catalytic Reduction (SNCR)	424	\$1,208,302	\$2,851
Ultra-low NOx burners (ULNBs)	452	\$232,800	\$515
ULNBs + OFA	509	\$337,751	\$664
ULNB/SCR layered approach	1,175	\$6,182,800	\$5,260
Selective Catalytic Reduction (SCR)	1,175	\$6,340,000	\$5,395

Drake Unit 7 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Overfired air (OFA)	416	\$75,217	\$181
Ultra-low NOx burners (ULNBs)	583	\$386,000	\$662
Selective Non-Catalytic Reduction (SNCR)	624	\$2,018,575	\$3,233
ULNBs + OFA	749	\$461,217	\$616
ULNB/SCR layered approach	1,709	\$8,196,000	\$4,797
Selective Catalytic Reduction (SCR)	1,709	\$8,510,000	\$4,981

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB - not significant
- ULNB - not significant
- SNCR and SCR - increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Drake - Unit 5		Drake - Unit 6		Drake - Unit 7	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Max (3-yr)	0.62		0.83		0.71	
OFA (annual avg.)	0.30	0.07	0.33	0.18	0.31	0.22
ULNB (annual avg.)	0.28	0.08	0.28	0.193	0.28	0.24
ULNB + OFA (annual avg.)	0.27	0.08	0.27	0.20	0.25	0.26
SNCR (annual avg.)	0.27	0.08	0.29	0.19	0.28	0.24
ULNB + SCR	0.07	0.12	0.07	0.27	0.07	0.37
SCR (annual avg.)	0.07	0.12	0.07	0.27	0.07	0.37

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: \$1,342 per ton NOx removed
- Unit 6: \$664 per ton NOx removed
- Unit 7: \$616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described (e.g. less than 0.50 Δ dv). For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv.

Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected

limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6. For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7. A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 & 7 can be found in Appendix C.

6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative which includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3

Background

Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with Section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.

The PSCo BART Alternative Program (“PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air - Clean Jobs Act” (§ 40-3.2-201 C.R.S., *et. seq.*). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed.

Table 6-5: Actions and Dates under the PSCo Alternative

Facility	Unit	Action or Control	Effective Date
Arapahoe	Unit 3	Shutdown	12/31/2013
	Unit 4	Operation on Natural Gas only (peaking unit)	12/31/2014
Cherokee	Unit 1	Shutdown	No later than 7/1/2012
	Unit 2	Shutdown	12/31/2011
	Unit 3	Shutdown	No later than 12/31/2016
	Unit 4	Operation on Natural Gas only	12/31/2017
Valmont		Shutdown	12/31/2017
Pawnee		SCR & LSD	12/31/2014

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

- 1) A list of all BART-eligible sources within the state;
- 2) A list of all BART-eligible sources and source categories covered by the alternative program;
- 3) An analysis of the best system of continuous emission control technology available and the associated reductions;
- 4) An analysis of the projected emissions reductions achievable through the alternative measure; and
- 5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NO_x and SO₂ emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state’s alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state’s analysis must include:

An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

40 CFR § 51.308(e)(2)(i)(C).

Colorado’s alternative program was designed to meet a requirement other than BART; namely, Colorado’s HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL “CLEAN AIR ACT”, 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO’S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO’S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO’S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado’s Clean Air - Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. See, § 40-3.2-204, C.R.S. PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART.

This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

[T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by-source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also*, 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See*, 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id.* at 60615 (“Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not necessary to assure that the alternative program will result in greater reasonable progress than BART.”).

The PSCo BART Alternative includes only EGUs and, based on EPA’s Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id.* The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU’s of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state’s analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

Analysis under 40 CFR Part 51, § 308(e)

(2)(i)(A) A list of all Bart-eligible sources within the State.

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with Section 302(c) or section 308(e)(1), or otherwise be addressed under Section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

Table 6-6: Sources Included Within the PSCo Alternative

Facility	Unit	Action or Control
Arapahoe	Unit 3	Shutdown
	Unit 4	Operation on natural gas only
Cherokee	Unit 1	Shutdown
	Unit 2	Shutdown
	Unit 3	Shutdown
	Unit 4 (BART-eligible)	Operation on natural gas only
	New nat. gas-fired EGU	BACT where netting does not apply
Valmont	(BART-eligible)	Shutdown
Pawnee	(BART-eligible)	SCR & LSD

(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq.*). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. See, 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.²⁰ The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

²⁰ None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. See, e.g., 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8. With respect to SO₂ emissions, the PSCo BART Alternative will reduce SO₂ emissions from these units by 21,493 tons per year in the first planning period (2010 to 2018). With respect to NO_x emissions, the PSCo BART Alternative will reduce NO_x emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail and demonstrates that for both SO₂ and NO_x, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

(2)(ii) [Reserved]

(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO₂ and NO_x at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NO_x emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets".

The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation Number 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation Number 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO₂ or NO_x from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Regulation Number 3, Part F.

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

(3)(i) Visibility does not decline in any Class I area, and

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non-BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

- a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.
- b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.
- c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.
- d) Pawnee Unit 1 (BART eligible unit) will install and operate an LSD to control SO₂ emissions and SCR to control NO_x emissions in 2014.

(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs

Colorado is not participating in the CAIR program.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)-(h).

No Colorado BART sources have applied for an exemption from BART.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART-eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative.

EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. See, e.g., 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO₂ or a lb/MMBtu for NO_x based on boiler and coal type. See 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule."). As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe.

For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO₂ that would be emitted under the PSCo BART Alternative to the number of tons of SO₂ that would be emitted by the same units if the standard of 0.15 lb SO₂/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO₂ removal, or an emission rate of 0.15 lb SO₂/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe Unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO₂/MMBtu was used for the alternative.

Table 6-7: SO₂ Reductions beyond Presumptive BART for PSCo Alternative

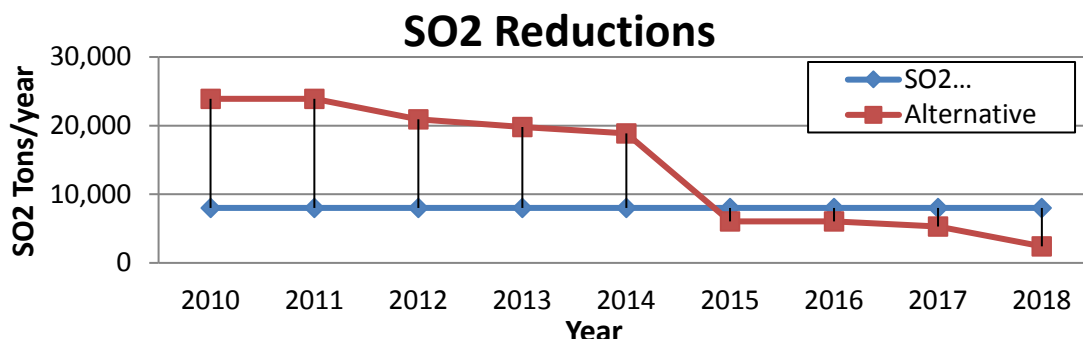
Facility	MMBtu Average 2006 to 2008	SO ₂ TPY Average 2006 to 2008	SO ₂ TPY at 0.15 lb/MMBtu Presumptive	SO ₂ TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28 ²¹	99.8%
Cherokee					
Unit 1	8,311,352	2,220.80	623.35	0.00	100.00%
Unit 2	5,586,021	1,888.37	418.95	0.00	100.00%
Unit 3	8,159,889	743.00	611.99	0.00	100.00%
Unit 4	26,047,648	2,135.43	1,953.57	7.81	99.6 %
Valmont	13,722,507	758.47	1,029.19	0.00	100.00%
Pawnee	40,093,753	13,472.07	3,007.03	2,405.63	20.00%
Total	114,847,083	23,908	8,614	2,415	71.97%

The comparison with the standard of 0.15 lb SO₂/MMBtu shows that the PSCo BART Alternative provides 72% lower SO₂ emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO₂/MMBtu standard for this planning period.

²¹ Emission factor of 0.0006 lb SO₂/MMBtu and 50% capacity factor.

Figure 6-1: SO₂ reductions beyond presumptive BART for PSCo Alternative



A similar analysis was completed for NO_x emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NO_x limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NO_x lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NO_x emitted from Arapahoe 4 operating on natural gas as a “peaking” unit, 300 tpy of NO_x reserved for “netting” or “offsets” from the Arapahoe facility, and 500 tpy of NO_x reserved for “netting” or “offsets” from the Cherokee facility.

Table 6-8: NO_x Reductions beyond Presumptive BART for PSCo Alternative

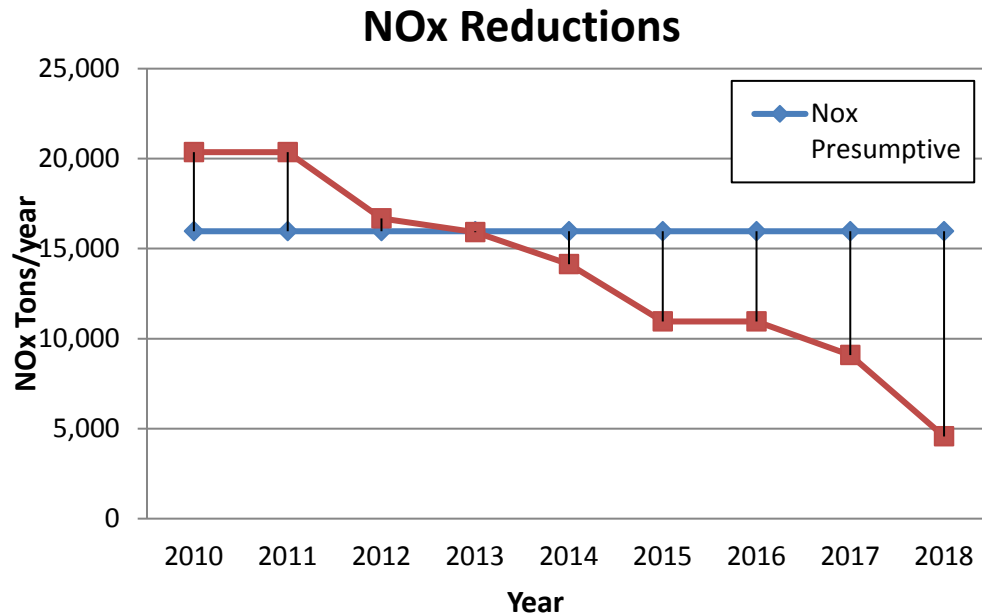
Facility	MMBtu Average 2006 to 2008	NO _x TPY Average 2006 to 2008	NO _x lb/MMBtu Standard	TPY NO _x at Standard	TPY NO _x Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00 ²²	8.42%
Cherokee						
Unit 1	8,311,352	1,556.23	0.39	1,620.71	0.00	100.00%
Unit 2	5,586,021	2,895.20	0.39	1,089.27	0.00	100.00%
Unit 3	8,159,889	1,865.50	0.39	1,591.18	0.00	100.00%
Unit 4	26,047,648	4,274.00	0.28	3,646.67	2,062.86 ²³	43.43%
Valmont	13,722,507	2,313.73	0.28	1,921.15	0.00	100.00%
Pawnee	40,093,753	4,537.73	0.23	4,610.78	1,403.28	69.57%
Total	114,847,083	20,361		15,966	4,366	72.65%

²² 600 tpy NO_x from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NO_x reserved for “netting” and “offsets” for additional natural gas generation. The 300 tpy NO_x is associated with unit 4 for illustrative purposes, but may be associated with either unit.

²³ Cherokee 4 operating on natural gas at 0.12 lb NO_x/mmBTU and 500tpy NO_x reserved for “netting” or “offsets”. The 500 tpy NO_x is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

Figure 6-2: NOx Reductions beyond Presumptive BART for PSCo Alternative



The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO₂ from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO₂ and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO₂ reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. See 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. See U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NO_x reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NO_x reductions. As part of its five factor consideration the state has elected to generally employ criteria for NO_x post-combustion control options to aid in the assessment and determinations for BART - a \$/ton of NO_x removed cap, and two minimum applicable Δ dv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NO_x post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than \$5,000 per ton of NO_x removed or the visibility improvement from SCR is less than 0.50 Δ dv. See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCo BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NO_x with less than 2ppm NH₃ slip and 54% reduction with a 10ppm NH₄ slip.²⁴ Because of the high ammonia slip at the higher range of NO_x removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NO_x reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NO_x.²⁵

²⁴ Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

²⁵ This level of NO_x control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NO_x reduction performance from application of SNCR.

Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

Table 6-9: NOx reductions beyond state criteria for PSCo Alternative

Facility	SCR \$/ton	SNCR \$/ton	SNCR TPY at 50% ²⁶	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900 ²⁷	-56.84%
Cherokee					
Unit 1	N/A	\$8,737	778.12	0	100.00%
Unit 2	N/A	\$3,963	1,447.60	0	100.00%
Unit 3	\$10,134	\$3,485	932.75	0	100.00%
Unit 4	\$6,252	\$2,625	2,137.00	2,062 ²⁸	3.47%
Valmont	\$8,647	\$3,328	1,156.87	0	100.00%
Pawnee	\$4,371	\$3,082	2,268.87	1,403	38.15%
Total			10,180	4,366	57.11%

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.²⁹

²⁶ Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

²⁷ 600 tpy NOx from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NOx reserved for “netting” and “offsets” for additional natural gas generation.

²⁸ Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for “netting” or “offsets”.

²⁹ This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the

The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

Table 6-10: SO₂ Reductions beyond Source-By-Source BART for PSCo Alternative

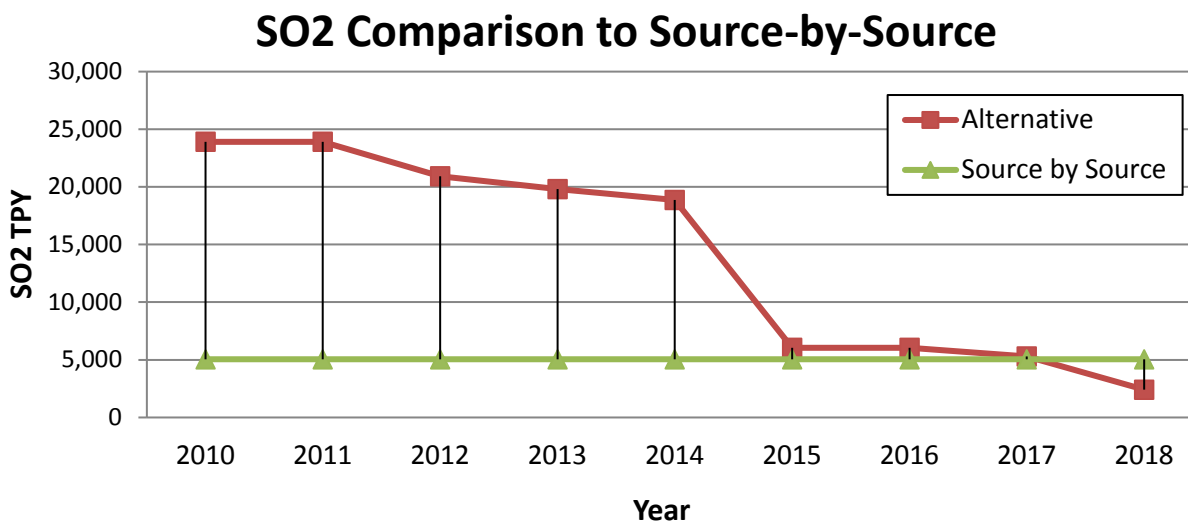
Facility	SO ₂ TPY from AP-42	Source-by-Source	SO ₂ TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57 ³⁰	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62 ³¹	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO₂.

³⁰ The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO₂/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

³¹ The Pawnee BART evaluation concluded that a 0.12 lb SO₂/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

Figure 6-3: SO₂ Reductions beyond Source-By-Source BART for PSCo Alternative



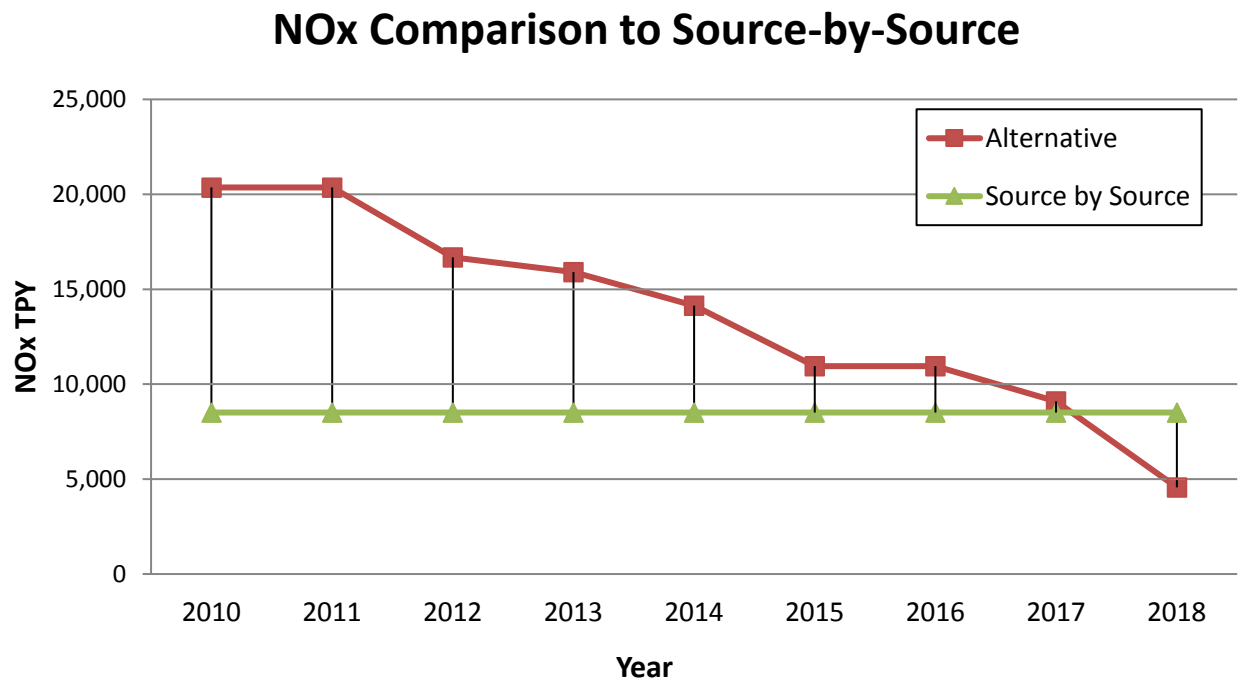
For NO_x the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.³² The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NO_x for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NO_x from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

³² This level of NO_x reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NO_x reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

Table 6-11: NOx Reductions beyond Source-By-Source BART for PSCo Alternative

Facility	NOx TPY from AP-42	Source-by-Source	NOx TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	2,149.15	214.91	0.00	100.00%
Unit 4	4,636.00	600	900.00 ³³	-50.00%
Cherokee				
Unit 1	3,596.54	359.65	0.00	100.00%
Unit 2	3,415.03	341.50	0.00	100.00%
Unit 3	4,411.28	441.12	0.00	100.00%
Unit 4	7,878.04	2,735.00 ³⁴	2,062.86 ³⁵	24.58%
Valmont	2,061.04	206.10	0.00	100.00%
Pawnee	7,945.11	3,608.43	1,403.28	61.11%
Total	36,092	8,507	4,366	48.67%

Figure 6-4: NOx Reductions beyond Source-By-Source BART for PSCo Alternative



³³ Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

³⁴ Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

³⁵ Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

Table 6-12: PSCo Alternative Emissions Limits^{36, 37, 38}

Unit	NOx Control Type	NOx Emission Limit	SO2 Control Type	SO2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

³⁶ Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

³⁷ 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

³⁸ 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species. A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018. More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP

Colorado Mandatory Class I Federal Areas Uniform Progress Summary in Haze Index Metric <i>Based on WRAP CMAQ Modeling using the PRP 2018b</i>								
Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California - Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged. The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas.

The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO₂.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

Figure 7-2 Summary of PSAT Modeling for 2018

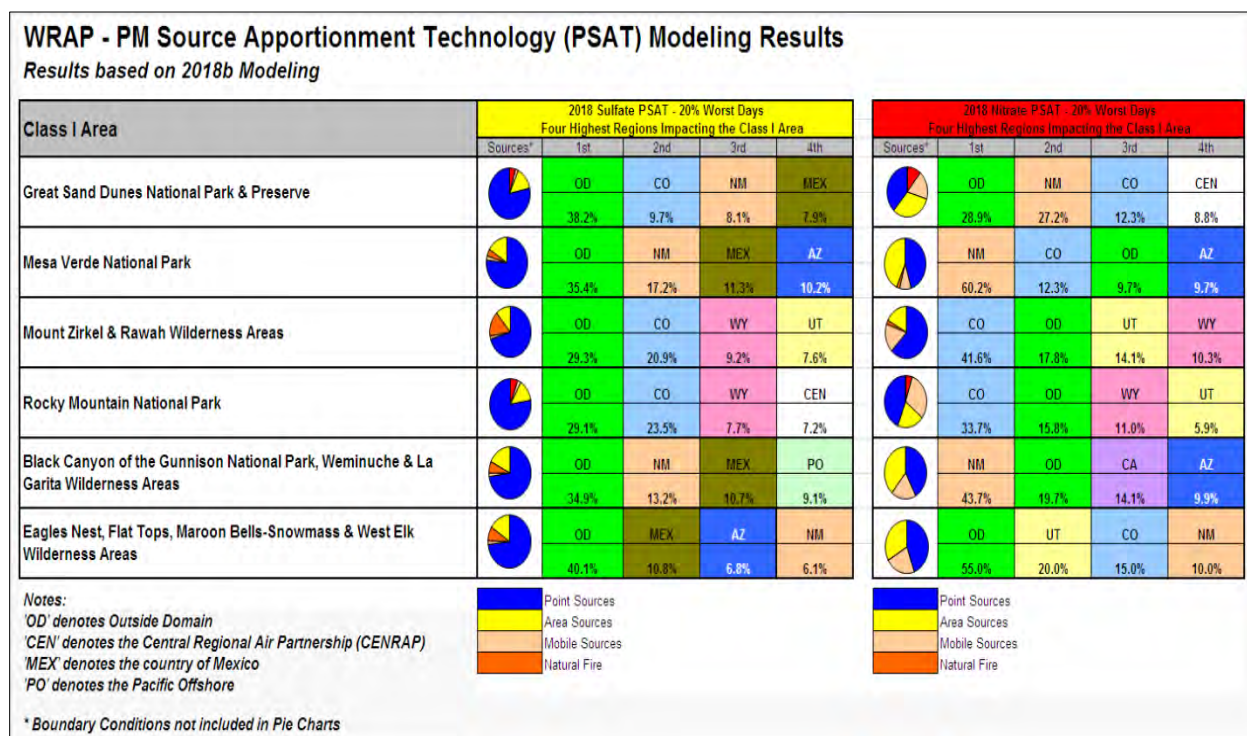


Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018

Change in Modeled Concentration for Colorado Share Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)									
Class I Area	Year	Total SO ₄ [ug/m ³]	Colorado SO ₄ [ug/m ³]	Colorado Share SO ₄	Colorado Sulfate Change	Total NO ₃ [ug/m ³]	Colorado NO ₃ [ug/m ³]	Colorado Share NO ₃	Colorado Nitrate Change
Great Sand Dunes National Park & Preserve	2002	0.440	0.057	13%		0.116	0.017	15%	
	2018	0.442	0.043	10%	-25%	0.114	0.014	12%	-18%
Mesa Verde National Park	2002	0.665	0.013	2%		0.249	0.026	10%	
	2018	0.644	0.009	1%	-31%	0.269	0.033	12%	+27%
Mount Zirkel & Rawah Wilderness Areas	2002	0.649	0.175	27%		0.214	0.085	40%	
	2018	0.621	0.130	21%	-26%	0.185	0.077	42%	-9%
Rocky Mountain National Park	2002	0.760	0.238	31%		0.339	0.128	38%	
	2018	0.677	0.159	23%	-33%	0.273	0.092	34%	-28%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	2002	0.484	0.024	5%		0.080	0.004	5%	
	2018	0.484	0.018	4%	-25%	0.071	0.005	7%	+25%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	2002	0.428	0.028	7%		0.020	0.004	20%	
	2018	0.424	0.021	5%	-25%	0.020	0.003	15%	-25%

Chapter 8 Reasonable Progress

8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation³⁹ of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO₂ (sulfate precursor), NO_x (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling.

³⁹ *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

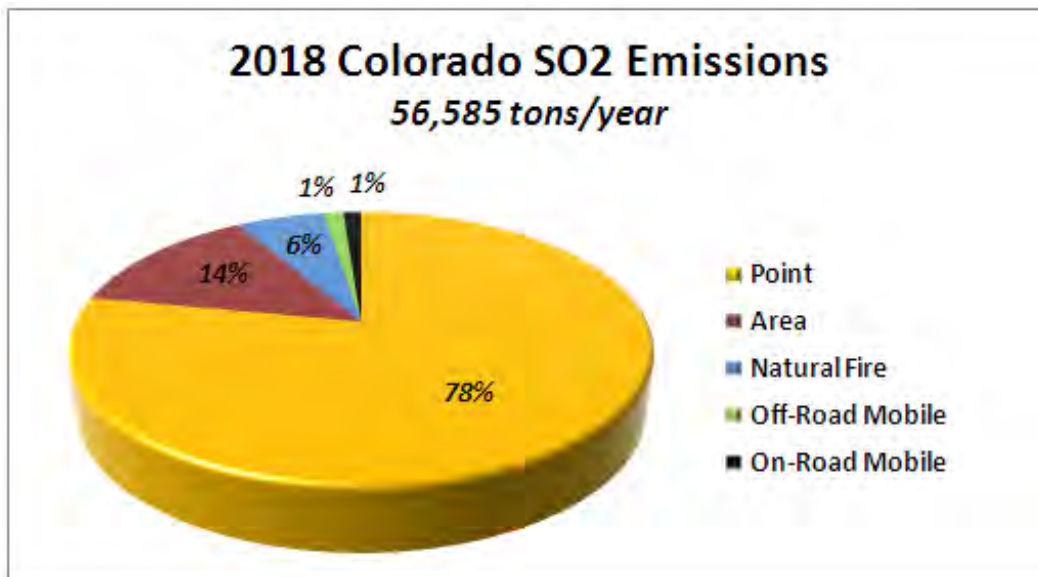
This determination is based on the well documented point source emission inventories for SO₂ and NO_x, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total SO₂, NO_x and PM emissions; d = distance from the nearest Class I area, as further described in Section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in Section 8.2.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO₂ emissions, which reflects “on-the-books (OTB)” and “on-the-way (OTW)” emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

Figure 8-1: Relative Source Contributions to Colorado SO₂ Emissions in 2018

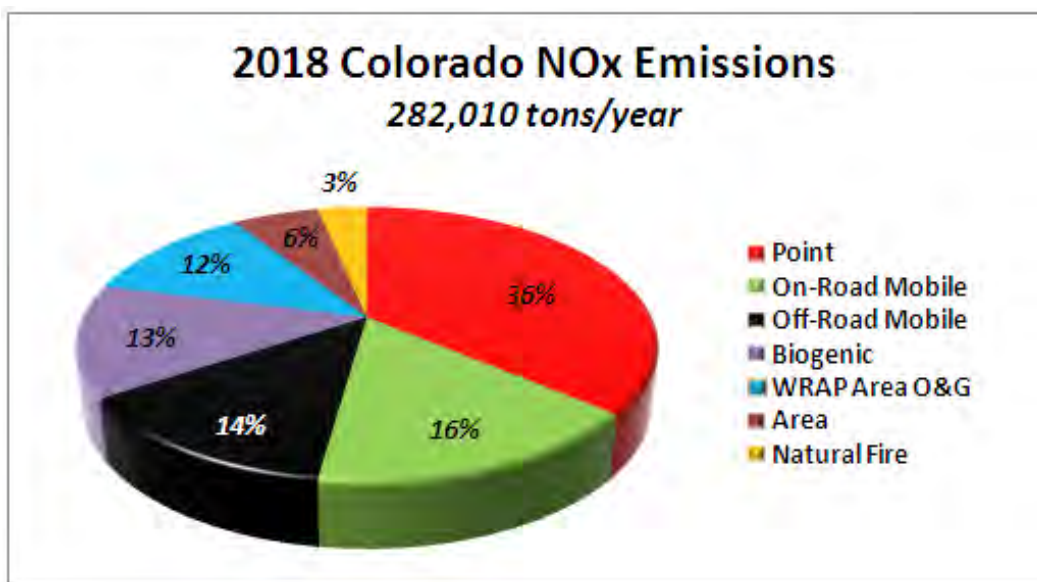


As indicated, 78% of total statewide SO₂ emissions are from point sources - largely coal-fired boilers. Area source SO₂ emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO₂ emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO₂.

Figure 8-2 provides the statewide projected 2018 NO_x emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

Figure 8-2: Relative Source Contributions to Colorado NO_x Emissions in 2018



Point sources comprise 36% of total NO_x emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NO_x emissions respectively. A portion of the on-road mobile source NO_x emissions reflect some level of NO_x control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period.

NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period. The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

8.3.1 Oil and Gas Heater Treaters

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

8.3.2 Reciprocating Internal Combustion Engines

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides (NO_x; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). NO_x are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NO_x emissions by design, and lean burn engines are designed to have relatively lower NO_x emissions.

Colorado has undertaken regulatory initiatives to control NO_x emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation Number 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NO_x (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed \$5,000 per ton. Selective catalytic reduction was considered for the control of NO_x from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately \$22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation Number 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described, with the one exception that the \$5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NO_x emissions and is codified in Regulation Number 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NO_x control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NO_x control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado's emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NO_x. At an average of about 10 tons of NO_x emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NO_x reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NO_x per year from RICE of all sizes in Colorado. The NO_x control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE NO_x emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NO_x emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NO_x assumed growth in uncontrolled engines and did not account for the NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NO_x from engines is attributed to existing lean burn engines which are uncontrolled for NO_x (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ. A detailed 4-factor analysis for RICE can be found in Appendix D.

8.3.3 Combustion Turbines

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NO_x, but pipeline quality natural gas is inherently clean and low-emitting for SO₂ and PM₁₀ emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see Section 8.3 for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 - 2008 Reasonable Progress baseline period.

There are five Reasonable Progress facilities with combustion turbines - PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- NO_x - 40 tons per year
- SO₂ - 40 tons per year
- PM₁₀ - 15 tons per year

Facility - Turbine	Total 2006 - 2008 Averaged NO _x Annual Emissions (tpy)	Total 2006 - 2008 Averaged SO ₂ Annual Emissions (tpy)	Total 2006 - 2008 Averaged PM ₁₀ Annual Emissions (tpy)	Greater than <i>de minimis</i> levels?
Front Range Power Plant - Turbine #1	159.6	2.9	4.9	Yes - NO _x only
Front Range Power Plant - Turbine #2	147.9	2.8	4.9	Yes - NO _x only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NO_x combustion systems, and based on 2006 - 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NO_x reductions, respectively. There is one feasible emission control technology available for these turbines is adding post combustion technology - selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 - 90 percent from uncontrolled levels. Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NO_x reduced annually with a capital expenditure of at least \$15 million. The state estimates that SCR for these turbines will range from approximately \$57,000 - \$62,000 per ton of NO_x reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NO_x reductions are not cost-effective. The state has determined that NO_x RP for combustion turbines is existing controls and emission limits. A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control⁴⁰.

⁴⁰ Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas, March 31, 2010. See the Technical Support Document

This RP screening methodology involves a calculated ratio called “Q-over-d”, that evaluates stationary source emissions (mathematical sum of actual SO₂, NO_x and PM emissions in tons per year, denoted as “Q”) divided by the distance (in kilometers, denoted as “d”) of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than “20” approximated a delta deciview (Δ dv) impact ranging from 0.06 Δ dv to 0.56 Δ dv. The resultant average of the range is about 0.3 Δ dv, which is a more conservative RP threshold than the 0.5 Δ dv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM₁₀) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO₂, NO_x or PM₁₀ emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as “significant” sources for purposes of reasonable progress.

Figure 8-3: Point Sources with >100 TPY of Emissions

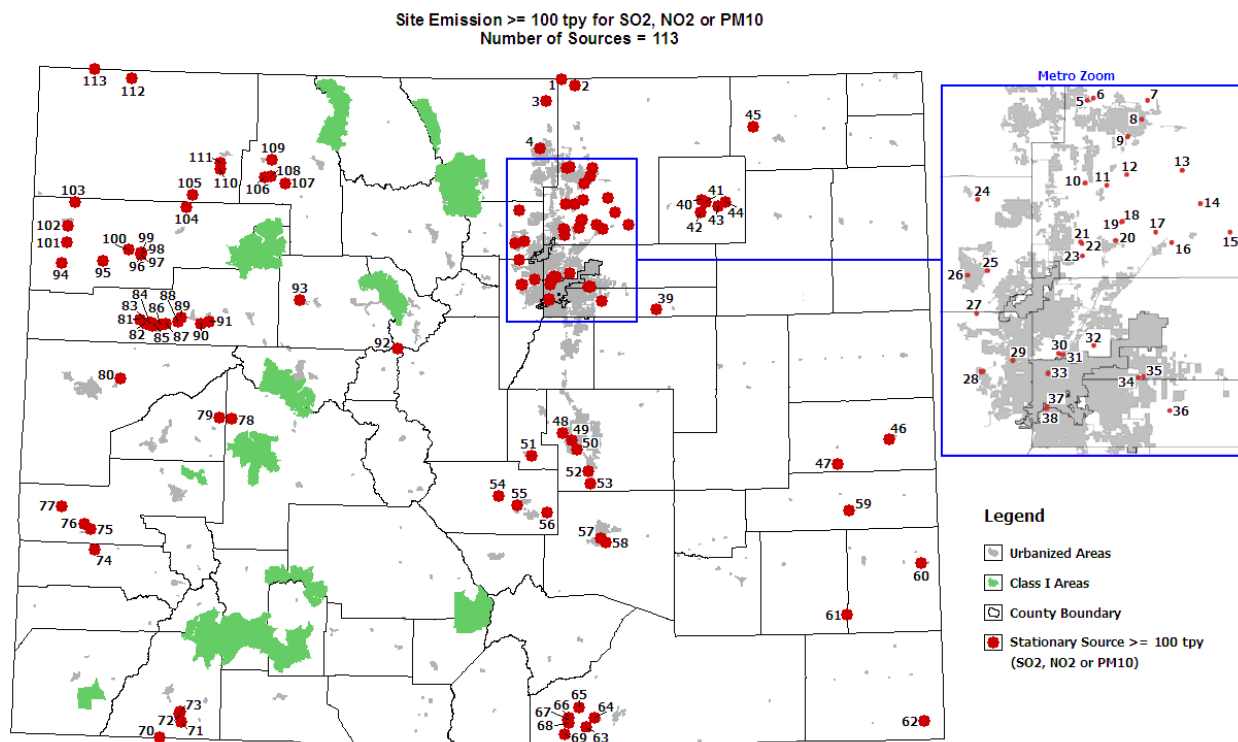


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

ArcGIS DATA - Statewide Sources over 100 tpy for SO ₂ , NO _x and PM ₁₀ (based on 2007 data)								
Count	FACILITY NAME	SO ₂ [tpy]	NO ₂ [tpy]	PM ₁₀ [tpy]	Q [tpy]	Closest CIA	d [km]	Q/d
1	PLATTE RIVER POWER AUTHORITY - RAWHIDE	854	1,808	134	2,796	Rocky Mnt NP	56.0	49.9
2	CEMEX INC. - LYONS CEMENT	87	2,479	418	2,984	Rocky Mnt NP	24.8	120.3
3	PUBLIC SERVICE CO - VALMONT	749	2,355	58	3,162	Rocky Mnt NP	34.8	90.9
4	COLORADO ENERGY NATIONS CORPORATION	2,826	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,681	Rocky Mnt NP	66.3	269.2
6	PUBLIC SERVICE CO - ARAPAHOE	2,496	2,922	178	5,595	Rocky Mnt NP	73.3	76.3
7	PUBLIC SERVICE CO - PAWNEE	13,073	4,645	193	17,911	Rocky Mnt NP	155.7	115.0
8	COLORADO SPRINGS UTILITIES - DRAKE	8,431	3,826	251	12,507	Great Sand Dunes NP	114.0	109.7
9	COLORADO SPRINGS UTILITIES - NIXON	3,883	2,656	129	6,668	Great Sand Dunes NP	104.4	63.9
10	AQUILA INC. - W.N. CLARK STATION	1,480	869	44	2,393	Great Sand Dunes NP	58.7	40.8
11	HOLCIM (US) INC. PORTLAND CEMENT	372	2,589	288	3,250	Great Sand Dunes NP	66.0	49.2
12	PUBLIC SERVICE CO - COMANCHE	13,854	8,415	178	22,447	Great Sand Dunes NP	84.5	265.6
13	TRI STATE GENERATION - NUCLA	1,509	1,716	101	3,327	Black Canyon NP	70.6	47.1
14	PUBLIC SERVICE CO - CAMEO	2,686	1,051	112	3,750	Black Canyon NP	70.6	53.2
15	PUBLIC SERVICE CO - HAYDEN	2,657	7,694	284	10,634	Mt Zirkel WA	31.6	336.5
16	TRI STATE GENERATION - CRAIG	3,586	16,807	235	20,628	Fiat Tops WA	47.7	432.4
Totals:		65,358	71,821	2,906				

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation Number 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. See U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (Unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit.
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO₂, NO_x and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCO) Valmont Power Plant (Unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO₂ and NO_x (see Chapter 6), which satisfies the SO₂ and NO_x BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO₂, NO_x and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler.
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); Unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO₂ and NO_x (see Chapter 6), which satisfies the SO₂ and NO_x BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For Unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO₂ and NO_x (see Chapter 6), which satisfies the SO₂ and NO_x BART/RP requirements in this planning period. For PM, the closure of Unit 3 by 2018 satisfies the PM RP requirements in this planning period; for Unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (Unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO₂ and NO_x (see Chapter 6), which satisfies the SO₂ and NO_x BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (Units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO₂, NO_x and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (Unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources.
10. The state has determined that the Black Hills Energy Clark Power Plant (Units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source.
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source.
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO₂, NO_x and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source.
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO₂, NO_x, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation Number 3.
15. The PSCo Hayden Power Plant (Units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO₂, NO_x and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO₂, NO_x and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO₂, NO_x and PM BART/RP requirements in this planning period. The state has determined that Unit 3 is subject-to-RP and has conducted an emission control analysis for the unit.

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

- (1) The costs of compliance,
- (2) The time necessary for compliance,
- (3) The energy and non-air quality environmental impacts of compliance, and
- (4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. See U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

8.5.1 Rationale for Point Source RP Determinations

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NO_x controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

8.5.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO₂ and NO_x control equipment. The cost for each unit is summarized and the State's consideration of this factor for each source is presented in detail in Appendix D.

8.5.1.2 The time necessary for compliance.

Regulation Number 3, Part F, Section VI.B.4. Requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

8.5.1.3 The energy and non-air quality environmental impacts of compliance.

This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO₂, as further described.

8.5.1.4 The remaining useful life of the source. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation Number 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented and in Appendix D.

8.5.1.6 Overview of the RP Determinations for Each Source. This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". See, 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO₂ controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. See, 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NO_x controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NO_x controls, as appropriate. When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO₂ and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO₂ and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NO_x controls on reasonable progress electric generating units, for reasons described, the state is employing guidance criteria to aid in its RP assessment, largely because significant NO_x add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO₂ emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO₂ control systems operating at electric generating units in Colorado.⁴¹ There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO₂ emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO₂ emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NO_x emissions, post-combustion controls for NO_x are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NO_x emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NO_x emissions.

⁴¹ EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

In assessing and determining appropriate NO_x controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (e.g., expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NO_x) from the atmosphere, or \$/ton of NO_x removed); and, (ii) visibility improvement expected from the control options analyzed (e.g., expressed as visibility improvement in delta deciview (Δ dv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NO_x post-combustion control options to aid in the assessment and determinations for BART - a \$/ton of NO_x removed cap, and two minimum applicable Δ dv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NO_x post-combustion control options (i.e., SCR systems for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x post-combustion control options (e.g., SNCR technologies for electric generating units) that do not exceed \$5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the \$5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.⁴²

⁴² Air Quality Control Commission Regulation Number 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

In that case, a \$5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.⁴³ The \$5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of \$5,000/ton (and lower), while control costs for Colorado BACT can be in the range of \$5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NO_x controls, *i.e.*, SCR, have the ability to provide significant NO_x reductions, but also have initial capital dollar requirements that can approach or exceed \$100 million per unit.⁴⁴ The lesser-performing post-combustion NO_x controls, *e.g.*, SNCR, reduce less NO_x on a percentage basis, but also have substantially lower initial capital requirements, generally less than \$10 million.⁴⁵ The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NO_x controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.⁴⁶ For the lesser-performing add-on NO_x controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NO_x controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

⁴³ The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

⁴⁴ See, *e.g.*, Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, \$83MM; Public Service of Colorado, Hayden Unit #2, \$72MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$210MM.

⁴⁵ See, *e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, \$1.4MM; Public Service Company of Colorado, Hayden Unit #2, \$4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, \$13.1MM

⁴⁶ The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources					
Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO ₂ Control Type	SO ₂ Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 & 2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average) ***	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe. The following presents an overview of Colorado's RP control determinations:

8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NO_x Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

SO₂ RP Determination for PRPA Rawhide Unit 101

Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO₂ reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives:* Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO₂ scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent:* Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent:* The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO₂ scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.

- *Engineering redesign of atomizer or slurry injection system:* The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO₂ emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state. The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - SO ₂ Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Fuel switching - NG	906	\$237,424,331	\$262,169

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO₂ emission limits as a demonstration are as follows:

SO ₂ Control Method	SO ₂ Annual Emission Rate (lb/MMBtu)	98 th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.11	
Existing Dry FGD	0.09	0.01
Dry FGD - tighter limit	0.07	0.03
Fuel switching - NG	0.00	0.87

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO₂ RP is the following SO₂ emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO₂ control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO₂ limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

Particulate Matter RP Determination for PRPA Rawhide

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NO_x emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
ECC	448	\$288,450	\$644
SNCR	504	\$1,596,000	\$3,168
Fuel switching - NG	545	\$237,424,331	\$435,681
SCR	1,185	\$12,103,000	\$10,214

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NO _x Control Method	NO _x Annual Emission Rate (lb/MMBtu)	98 th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.302	
ECC	0.126	0.45
SNCR	0.121	0.46
Fuel Switching - NG	0.118	0.47
SCR	0.061	0.59

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State's RP determination. Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV. Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NO_x RP for Rawhide Unit 101 is the following NO_x emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in Section 8.4. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state. A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

SO₂ RP Determination for CENC - Boiler 3

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO₂ emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 3 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
DSI - Trona	147	\$1,340,661	\$9,114
Fuel Switching - Natural Gas	245	\$1,428,911	\$5,828

DSI - Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO₂ RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<0.10 dv) afforded.

Particulate Matter RP Determination for CENC - Boiler 3

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM₁₀) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CENC - Boiler 3

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfired air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
FGR	33.7	\$1,042,941	\$30,929
SNCR	50.6	\$513,197	\$10,146
Fuel switching - NG	84.3	\$1,428,911	\$16,950
ROFA w/ Rotamix	77	\$978,065	\$9,496
Regenerative SCR	96.3	\$978,065	\$10,160
High temperature SCR	125.6	\$1,965,929	\$15,651
Low temperature SCR	144.5	\$2,772,286	\$19,187

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in Section 8.4. All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in Section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution (NO_x , SO_2 , PM_{10}) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NO_x and SO₂ Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

SO₂ RP Determination for CSU - Nixon

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO₂ emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nixon Unit 1 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
DSI - Trona	2,473	\$9,438,692	\$1,997
Dry FGD @ 78% control (0.10 lb/MMBtu annual average)	3,215	\$12,036,604	\$3,744
Dry FGD @ 85% control (0.07 lb/MMBtu annual average)	3,392	\$13,399,590	\$3,950

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD - less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Nixon - Unit 1	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Max (3-yr)	0.45	
DSI	0.18	0.44
Dry FGD (LSD)	0.10	0.46
Dry FGD (LSD)	0.07	0.50

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO₂ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: \$3,744 per ton SO₂ removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

Particulate Matter RP Determination for CSU - Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CSU - Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Nixon Unit 1 - NO _x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Ultra-low NOx Burners (ULNBs)	471	\$567,000	\$1,203
Overfired Air (OFA)	589	\$403,000	\$684
ULNBs+OFA	707	\$907,000	\$1,372
Selective Non-Catalytic Reduction (SNCR)	707	\$3,266,877	\$4,564
ULNB/SCR layered approach	1,720	\$11,007,000	\$6,398
Selective Catalytic Reduction (SCR)	1,720	\$11,010,000	\$6,400

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB - not significant
- ULNB - not significant
- SNCR - increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Nixon - Unit 1	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.26	
ULNB	0.21	0.15
OFA	0.19	0.15
ULNB+OFA	0.18	0.16
SNCR	0.18	0.16
ULNB + SCR	0.07	0.24
SCR	0.07	0.24

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement. The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the RP determination.

However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1. A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shut down 12/31/2013, resulting in SO₂, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

8.5.2.5 RP Determination for Holcim's Florence Cement Plant

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_x, SO₂, and PM/PM₁₀ emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM₁₀, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO₂, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_x precalciner, indirect firing, Low-NO_x burners, staged combustion and a Linkman Expert Control System for NO_x, and by the use of good combustion practices for both NO_x and SO₂. In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM₁₀ emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill.

Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses. Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion NO_x controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a SO₂ emission rate of 99.17 lbs/hour, a NO_x emission rate of 837.96 pounds per hour (lbs/hour), and a PM₁₀ emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM₁₀ emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

SO₂ RP Determination for Holcim Portland Plant - Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO₂ emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO₂ emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO₂ from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO₂ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO₂).

The actual kiln SO₂ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO₂ per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO₂. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO₂ per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO₂ value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO₂, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO₂ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies - the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber.

The RP analysis provides sufficient basis to establish a short-term SO₂ emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO₂ per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO₂ per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Particulate Matter RP Determination for Holcim Portland Plant - Kiln System

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding PM₁₀ emissions rates. The facility is currently permitted to emit 246.3 tpy of PM₁₀ from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM₁₀ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM₁₀). The actual kiln system PM₁₀ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM₁₀ per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for PM₁₀, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates - the baseline emission rate of 0.08 pound of PM₁₀ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM₁₀ per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change.

The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO₃) followed by sulfates (SO₄). The contribution of PM₁₀ to the total visibility impairment was insignificant in the analysis. The level of PM₁₀ emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM₁₀ emissions from the kiln system on visibility impairment, the state has determined that no additional PM₁₀ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology - fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM₁₀ (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source.

Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM₁₀ emissions.

NO_x RP Determination for Holcim Portland Plant - Kiln System

There are a number of technologies available to reduce NO_x emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NO_x burners, staged combustion, a low-NO_x precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NO_x emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.”

Based on our research and EPA’s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000°F) for reducing NO_x to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006.

Holcim estimated that NO_x emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of \$1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency $[4.47/0.9*(1-0.45) = 2.73]$. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency $[3.64/0.9*(1-0.45) = 2.23 \text{ lb/ton}]$. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NOx Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NOx Emissions (tpy)
Baseline NOx Emissions	-	4.97	3,185.7*
SNCR w/ existing LNB	45%**	2.73	2,086.8

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant - Kiln System				
NOx Control Technology	NOx Emission Reduction (tons/yr)	Annualized Cost (\$/yr)	Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline NOx Emissions	-			
SNCR w/existing LNB (45% control)	1,098.9	\$2,520,000*	\$2,293	-

* Annualized cost is based on the estimates provided by Holcim. The state believes that the \$2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_x RP limitations. The following table lists the projected visibility improvements for NO_x controls, as identified by Holcim:

Holcim Portland Plant - Kiln System		
NO _x Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NO _x , 586 lb/hr SO ₂ , 86.4 lb/hr PM ₁₀)	0.814	N/A
SNCR w/ existing LNB (45% overall NO _x control efficiency) Limits of 2.73 lb/ton (30-day rolling average) and 2,086.8 tons per year (based on modeled emission rates of 750 lb/hr NO _x , 586 lb/hr SO ₂ , 86.4 lb/hr PM ₁₀)	0.526	0.288

For the kiln, the state has determined that SNCR w/existing LNB is the best NO_x control system available with NO_x RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_x reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement. A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO₂ RP Determination for Nucla - Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO₂ emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs.

Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis. The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO ₂ Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
Limestone Injection Improvements	526	\$914,290	\$4,161
Spray Dry Absorber (dry FGD)	1,162	\$7,604,627	\$6,547
Limestone Injection Improvements + dry FGD	1,254	\$9,793,222	\$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO₂ reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage. There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period. Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO₂ emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO₂ capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO₂ emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO₂ system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO₂ emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla - Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla - Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 - 40% NOx reduction potential, which correlates to between \$3,000 - \$17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year. The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 - 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options.

A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NO_x control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO₂ and NO_x control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO₂ and NO_x emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO₂ control and existing SNCR for NO_x reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NO_x reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NO_x limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review for the Nucla facility can be found in Appendix D.

8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO₂ RP Determination for Craig - Unit 3

Dry FGD Upgrades - As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO₂ reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives:* Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO₂ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.
- *Use of more reactive sorbent/Increase the pulverization level of sorbent:* The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent.
- *Engineering redesign of atomizer or slurry injection system:* Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO₂ removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO₂ limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

SO ₂ Control Method	Craig - Unit 3	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ _{dv})
Daily Maximum (3-yr)	0.33	
Dry FGD	0.15	0.26
Dry FGD	0.07	0.38

The current SO₂ emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO₂, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO₂ BART is the following SO₂ emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO₂ limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

PM₁₀ RP Determination for Craig - Unit 3

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM₁₀) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NO_x RP Determination for Craig - Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NO_x emissions at Craig Unit 3. The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	853	\$4,173,000	\$4,887
SCR	4,281	\$29,762,387	\$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period. The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98 th Percentile Impact (Δdv)
Daily Maximum (2 nd half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions. Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in Section 8.4.

- Unit 3: \$4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in Section 8.4. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs. A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

8.5.2.8 RP Determination for Public Service Company's Cameo Station

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO₂, NO_x and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated. This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its' apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:

- (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- (2) Emission limitations and schedules for compliance to achieve the RP goal;
- (3) Measures to mitigate the impacts of construction activities;
- (4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
- (5) Source retirement and replacement schedules;
- (6) Enforceability of emission limitations and control measures; and
- (7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following Sections 9.2 and 9.3 address these LTS requirements.

9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized.

9.2.1 Existing Impairment

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation Number 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule.

As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation Number 3. In addition, Regulation Number 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado's requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

9.2.1.1 Mt. Zirkel Wilderness

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO₂ and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

9.2.1.2 BART and Emission Limitations

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation Number 3 result in new control requirements for these units to meet BART.

9.2.1.3 Monitoring

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of 'before and after emission reductions' will be met.

9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation Number 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado's Regulation Number 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation Number 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation Number 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

9.2.4 Federal Land Manager Consultation and Communication

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation Number 3, as described in Section 9.2.1, and a commitment to utilize the FETS to track fire data as described in Section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

9.4.1 Impacts on Other States

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands

Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were identified.

9.4.2 Impacts from Other States

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

9.4.3 Document Technical Basis for RPGs

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

9.4.4 Identify Anthropogenic Sources

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs

Following is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NO_x, SO₂ and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NO_x, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
 - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
 - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
 - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
 - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method - the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
 - Part A - Federal NSPS's adopted by the state - EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
 - Part B - state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
 - The majority of Regulation Number 7 for VOC and NO_x control is in the SIP or has been submitted for approval into the SIP - these provisions relate to VOC and NO_x control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized.
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting - state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program - Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions - In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO₂ from metro Denver power plants, approximately 6,500 tpy of SO₂ from the Comanche power plant, and approximately 18,000 tpy of SO₂ from the Craig and Hayden power plants - state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 - Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NO_x and VOC emissions reductions of approximately 8,900 tpy - In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range region that have achieved VOC emission reductions of approximately 8,400 tpy - state-only
- Mobile source emissions controls for VOCs and NO_x through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 - Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions - state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NO_x and VOC emissions reductions of approximately 7,100 tpy by 2010 - state-only
- PM₁₀ emission reduction programs in PM₁₀ maintenance areas throughout the state - In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide - In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide - state-only
- Renewable energy requirements that are driving current and future NO_x, SO₂ and PM emission reductions from coal-fired power plants - Ballot Initiative 37 - by requiring electricity to be obtained from renewable resources - state-only
- Attaining and maintaining the PM₁₀ and PM_{2.5} standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) - state-only

- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program - state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 - gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

<https://www.colorado.gov/cdphe/aqcc> As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

Table 9-1 shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

<u>PM10</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	10-year update: AQCC approved 12/16/10
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
<u>Carbon Monoxide</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	10-year update: AQCC approved 12/16/10

Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
<u>Ozone</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Denver/Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Regulation Number 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
<u>Lead</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Denver	EPA redesignated Denver attainment in 1984	
<u>Nitrogen Dioxide</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Denver	EPA redesignated Denver attainment in 1984	

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulation Numbers 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation Number 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation Number 1, Sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation Number 1 to most directly address these sources of fine and coarse particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation Number 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement⁴⁷. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation Number 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted.

⁴⁷ The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation Number 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;
- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
 - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
 - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permittees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a “high” smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division’s web site contains information about various aspects of Colorado’s Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: <https://www.colorado.gov/cdphe/smoke-management-permits>

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation Number 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation Number 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Numbers 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation Number 3. Unless otherwise indicated in those chapters or in Regulation Number 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 - the fleet turn-over rate was developed utilizing EPA-approved methodologies.

9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable.

Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources. Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO₂ emission reduction of 58,907 tons per year and a total NO_x emission reduction of 123,497 tons per year by 2018. (SO₂ and NO_x are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Uniform
Rate of
Progress for
2018

Projected
Amount of
Progress by
2018 towards
URP

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
 - 2010 BART alternative: 37,488 tons/year
 - 2010 RP: 12,624 tons/year
- Total: 70,846 tons/year

Also, 3,321 tons of additional NOx reductions will occur by 2021 due to a more stringent emission limit at Craig Unit 1 adopted in 2014. The revised total is 74,167 tons/year of visibility impairing pollutants reduced (due to BART and RP measures).

The following figures also present “CALPUFF” modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

Figure 9-3 Emission Reductions Achieved by BART Determinations

BART Emission Control Analysis						
NOx BART - SCR						
Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Hayden - Unit 2	\$ 71,780,853	\$ 12,321,491	3,032	\$ 4,064	0.82	23 (Zirkel)
Hayden - Unit 1	\$ 61,938,167	\$ 10,560,612	3,120	\$ 3,385	1.12	48 (Zirkel)
Craig - Unit 1 (SCR @ 78% reduction)	\$ 209,548,000	\$ 25,036,709	4,048	\$ 6,184	1.01	41 (Mt. Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	\$ 209,552,000	\$ 25,036,709	3,975	\$ 6,299	0.94	41 (Mt. Zirkel)
NOx BART - SNCR						
Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
CEMEX - Kiln	\$ 600,000	\$ 1,636,636	846	\$ 1,934	0.40	14 (RMNP)
NOx BART - Other						
Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5 (ULNB w/OFA)	\$ 2,895,672	\$ 288,844	215	\$ 1,342	0.08	> 0 (RMNP)
Drake - Unit 6 (ULNB w/OFA)	\$ 3,340,318	\$ 337,751	509	\$ 664	0.20	> 3 (RMNP)
Drake - Unit 7 (ULNB w/OFA)	\$ 4,500,232	\$ 461,217	749	\$ 616	0.26	> 3 (RMNP)
CENC (TriGen) - Unit 4 LNB, w/SOFA	\$ 4,284,900	\$ 678,305	214	\$ 3,170	0.08	3 (RMNP)
CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR	\$ 6,556,888	\$ 1,739,825	354	\$ 4,919	0.26	14 (RMNP)
CEMEX - Dryer T5 Permit Limits	\$ -	\$ -	0	\$ -	0.00	none
SO2 BART						
Source	Capital or O&M Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day)	\$ 6,000,000	\$ 1,340,663	762	\$ 1,761	0.12	2 (RMNP)
Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day)	\$ 38,000,000	\$ 6,665,771	2,368	\$ 2,816	0.24	3 (RMNP)
Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day)	\$ 44,166,000	\$ 9,577,538	3,764	\$ 2,544	0.39	6 (RMNP)
Hayden - Unit 1 Tighten Emission Limit to 0.13	\$165,000 parts & \$110,000 O&M	\$ 141,150	61	\$ 2,318	0.01	>12 (Mt. Zirkel)
Hayden - Unit 2 Tighten Emission Limit to 0.13	\$165,000 parts & \$110,000 O&M	\$ 141,150	39	\$ 3,629	0.05	>8 (Mt. Zirkel)
TOTAL CAPITAL COST		\$ 1,082,813,031				
TOTAL ANNUALIZED COST		\$ 146,037,789				
TOTAL NOx REDUCED			25,085	tons/year		
TOTAL SO2 REDUCED			6,993	tons/year		
TOTAL COMBINED POLLUTANTS REDUCED			32,079	tons/year		

Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

Facility	NOx Emissions Average 2006-2008 (tpy)	NOx Emissions from Alternative (TPY)	Total NOx Emissions Reduced (TPY)	SO2 Emissions Average 2006 -2008 (tpy)	SO2 Emissions from Alternative (TPY)	Total SO2 Emissions Reduced (TPY)
Arapahoe						
Unit 3	1,770	0		925	0	
Unit 4	1,148	900 ⁴⁸		1,765	1.28	
Cherokee						
Unit 1	1,556	0		2,221	0	
Unit 2	2,895	0		1,888	0	
Unit 3	1,866	0		743	0	
Unit 4	4,274	2,063 ⁴⁹		2,135	7.81 ⁵⁰	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403 ⁵¹		13,472	2,406 ⁵²	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

⁴⁸ Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

⁴⁹ Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

⁵⁰ Emissions at 0.0006 lb SO2/MMBtu

⁵¹ Emissions at 0.07 lb NOx/MMBtu

⁵² Emissions at 0.12 lb SO2/MMBtu

Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

RP Emission Control Analysis

NOx RP - SCR						
Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement

NOx RP - SNCR						
Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 3 (SNCR @ 15% Reduction)	\$ 13,139,000	\$ 4,173,000	854	\$ 4,886	0.32	6 (Mt. Zirkel)
Holcim Cement (establish limit)	not estimated	\$ 2,520,000	1,028	2,451	0.23	5 (GSDNP)

NOx RP- Other						
Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	861	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	516	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	624	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Nixon - Unit 1 (ULNB w/Overfire Air)	\$ 3,822,000	\$ 970,000	707	\$ 1,372	0.15	2 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (enhanced combustion control)	\$ 1,180,000	\$ 288,450	448	\$ 644	0.35	18 (RMNP)

SO2 RP						
Source	Capital Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	1,457	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	849	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	1,769	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Craig - Unit 3 (tighten existing emission limit)	none	none	0	n/a	0.26	6 (RMNP)
Holcim Cement (establish limit)	not estimated	not estimated	0	n/a	-	n/a
Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling)	\$ 96,160,000	\$ 12,036,604	3,215	\$ 3,744	0.46	11 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (no technically feasible options)	n/a	n/a	n/a	n/a	n/a	n/a

PM RP						
Source	Capital or O&M Costs	Annualized Costs	PM Reduced [tpy]	PM Control Cost [\$ /ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	72	n/a	n/a	n/a
Cameo - Units 1 & 2 (Shutdown)	n/a	n/a	225	n/a	n/a	n/a

TOTAL CAPITAL COST	\$ 114,301,000
TOTAL ANNUALIZED COST	\$ 19,988,054

TOTAL NOX REDUCED	5,038	tons/year
TOTAL SO2 REDUCED	7,290	tons/year
TOTAL PM REDUCED	297	tons/year
TOTAL COMBINED POLLUTANTS REDUCED	12,624	tons/year

Of these 74,121 tons of SO2 and NOx reduced due to BART and RP, approximately 47,821 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 presents this analysis for each of the BART and RP sources.

Figure 9-6 Difference between the WRAP and Final BART/RP Emissions for NO_x and SO₂

Additional NO_x and SO₂ Reductions						
<i>Difference between PRP2018b and Proposed BART/RP</i>						
PLANT	PRP 2018b NO _x [tpy]	2018 BART/RP NO _x [tpy]	Difference [tpy]	PRP 2018b SO ₂ [tpy]	2018 BART/RP SO ₂ [tpy]	Difference [tpy]
AQUILA, INC. - W.N. CLARK STATION	1,090	-	(1,090)	1,322	-	(1,322)
CEMEX, INC. - LYONS CEMENT PLANT	901	901	-	97	95	(2)
COLORADO SPRINGS UTILITIES - NIXON PLT	2,331	1,650	(681)	4,073	907	(3,166)
COLORADO SPRINGS UTILITIES - DRAKE PLT	3,669	2,789	(880)	2,701	1,590	(1,111)
HOLCIM (US) INC. PORTLAND PLANT	1,859	2,087	228	393	721	328
PLATTE RIVER POWER AUTHORITY - RAWHIDE	3,912	1,418	(2,494)	927	913	(14)
PUBLIC SERVICE CO - CAMEO (shutdown)	-	-	-	-	-	-
PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only)	-	900	900	-	1	1
PUBLIC SERVICE CO - VALMONT	2,279	-	(2,279)	879	-	(879)
PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4)	5,998	1,813	(4,185)	5,214	8	(5,206)
PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2)	4,317	250	(4,067)	1,750	-	(1,750)
PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2)	6,143	4,602	(1,541)	3,686	2,953	(733)
PUBLIC SERVICE CO COMANCHE PLT (Unit 3)	2,600	2,600	-	3,250	3,250	-
PUBLIC SERVICE CO HAYDEN PLT	7,307	1,341	(5,966)	2,898	2,541	(357)
PUBLIC SERVICE CO PAWNEE PLT	3,942	1,403	(2,539)	2,225	2,406	181
TRI STATE GENERATION CRAIG (Units 1 & 2)	10,974	2,539	(8,435)	2,117	1,952	(165)
TRI STATE GENERATION CRAIG (Unit 3)	5,825	4,839	(986)	1,823	1,863	40
TRI STATE GENERATION NUCLA	1,753	2,167	414	1,325	1,325	0
TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5)	1,185	722	(463)	2,624	2,762	138
TRIGEN - COLORADO ENERGY CORPORATION (Unit 3)	159	222	63	170	379	209
	66,243	32,243	(34,000)	37,473	23,666	(13,807)
Combined Reductions from NO_x and SO₂ Controls [tpy]:						(47,808)

These substantial additional emission reductions will further the amount of progress achieved. Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

Figure 9-7 Reasonable Progress Goals for Each Class I Area

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
<i>Great Sand Dunes National Park & Preserve</i>	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
<i>Mesa Verde National Park</i>	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
<i>Mount Zirkel & Rawah Wilderness Areas</i>	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
<i>Rocky Mountain National Park</i>	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
<i>Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas</i>	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
<i>Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas</i>	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Reasonable Progress Goals for 2018

No Degradation of Visibility for the Best Days

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated in Section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources.

Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures. Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable.

In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO₂, NO_x (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

Colorado Mandatory Class I Federal Areas Number of Years to Attain Natural Conditions <i>Based on WRAP CMAQ Modeling using the PRP 2018b</i>											
Mandatory Class I Federal Area	20% Worst Days									Number of years to NC [yrs]	New NC Goal [year]
	Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2064 Natural Conditions [dv]	Total Haze Delta (Baseline-2064 NC) [dv]	Haze Program Period [yrs]	Haze Program Reduction Rate [dv/yr]	2018 Modeling Projection [dv]	2018 Modeling <= 2018 UPG?	Recast Reduction Rate [dv/yr]		
Great Sand Dunes National Park & Preserve	12.78	11.35	6.66	6.12	60	0.102	12.20	No	0.041	148	2152
Mesa Verde National Park	13.03	11.58	6.81	6.22	60	0.104	12.50	No	0.038	164	2168
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	6.08	4.44	60	0.074	9.91	No	0.044	102	2106
Rocky Mountain National Park	13.83	12.27	7.15	6.68	60	0.111	12.83	No	0.071	94	2098
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	6.21	4.12	60	0.069	9.83	No	0.036	115	2119
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	6.06	3.55	60	0.059	8.98	No	0.045	79	2083

The following figures for Mesa Verde National Park illustrate the re-calculations.

Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

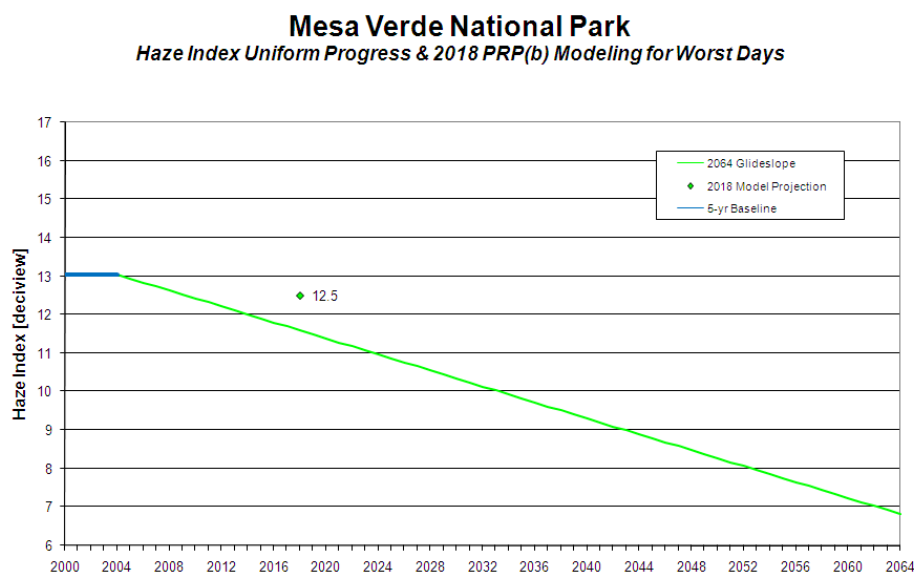
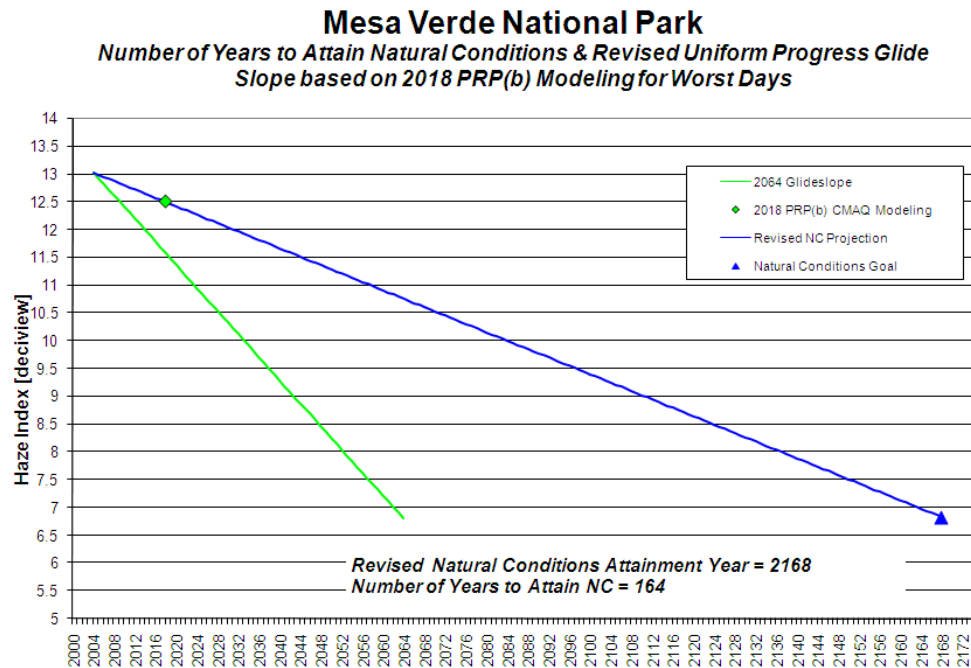


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

10.1 Future Consultation Commitments

10.1.1 FLM Consultation

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
 - a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
 - b. Summary of major new source permits issued;
 - c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
 - d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

10.1.2 Tribal Consultation

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

10.1.3 Inter-state Consultation/Coordination

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado's emissions may reasonable be anticipated to cause or contribute to visibility impairment in those State's federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

10.1.4 Regional Planning Coordination

As per the requirements of [51.308(c)(1)(i)], Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
3. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state.
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy.
3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period.

4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period.
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP.
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions.
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado. The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51.308(h)(1) through (4) that are applicable. These actions are described and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.
4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3) requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using the most recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

10.4.2 Long Term Strategy Effectiveness

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

10.4.3 Affirmation of or Revisions to Reasonable Progress Goals

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this Section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1)(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at <http://www.cdphe.state.co.us/ap/regionalhaze.html>

11.1 Class I Area Technical Support Documents (TSDs)

TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

Colorado State Implementation Plan for Regional Haze Technical Support Document - Black Canyon of the Gunnison National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Eagles Nest Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Flat Tops Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -La Garita Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document - Maroon Bells Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Mesa Verde National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Mount Zirkel Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Rocky Mountain National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Rawah Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Sand Dunes National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document - Weminuche Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -West Elk Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

11.2 Other Technical Support Documents

In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

Colorado State Implementation Plan for Regional Haze Technical Support Document -Douglas Pass and Ripple Creek Pass Sites, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document -Agricultural Burning in Colorado 2003-4 Inventory, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

11.3 Long-Term Strategy Review Update

In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

List of Appendices -

Appendix A - Periodic Review of Colorado RAVI Long Term Strategy

Appendix B - SIP Revision for RAVI Long Term Strategy

Appendix C - Technical Support for the BART Determinations

Appendix D - Technical Support for the Reasonable Progress Determinations

APPENDIX A

Regional Haze State Implementation Plan

Periodic Review of Colorado RAVI Long Term Strategy

LONG-TERM STRATEGY REVIEW

OF

COLORADO'S STATE IMPLEMENTATION PLAN

FOR CLASS I AREA VISIBILITY PROTECTION

ADDRESSING REASONABLY ATTRIBUTABLE

IMPAIRMENT

July 2007
(updated October 2007)

I. STATE OF COLORADO'S PHASE I STATE IMPLEMENTATION PLAN FOR CLASS I VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

The various elements of Phase I of Colorado's Class I Visibility State Implementation Plan are spread throughout Colorado Air Quality Control Commission Regulation No. 3. All of the components of the Visibility SIP are important to long-term visibility protection of Class I areas in the State and are integrated in varying degrees into the LTS review and revision protocol. Therefore, each of the components is briefly discussed in this section.

A. Existing Impairment.

The AQCC's Regulation No. 3, Stationary Source Permitting and Air Pollution Emission Notice Requirements, includes provisions to address impairment within Class I areas reasonably attributable to existing major sources.

Regulation No. 3 Part D §XIV.D provides for an affected FLM or the Division to certify visibility impairment in a Class I area due to an existing stationary source. Existing sources regulated under this program are those that were not in operation prior to August 7, 1962 nor for which construction was commenced on or after August 7, 1977, which have the potential to emit 250 tons or more of an air pollutant regulated by the Division.

The FLM or the Division may certify at any time that impairment exists in any Class I area. If the Division reasonably attributes the impairment to an existing source, the Division must conduct a BART analysis and determine if additional emission limitations are required. If so, the source must apply for a BART permit from the Division. Once the permit is granted, the source

must limit its emissions on a schedule not to exceed five years. At the time of Colorado's Visibility SIP development, the FLMs did not indicate that potentially reasonably attributable types of visibility impairment were present in any of Colorado's Class I areas. The Division concurred with the finding. However, in 1993 the USFS certified visibility impairment in the Mt. Zirkel Wilderness in northwest Colorado.¹ The certification has subsequently been resolved and is discussed below in section II.B.1.a.

B. New Source Review.

Applicants for permits to operate as a major source must demonstrate that the proposed source will not have an adverse impact on visibility in any Class I area. Regulation 3 Part D §XIII.A sets forth a schedule for the participation of affected FLMs and consultation with the Division in the review process of such an analysis as part of the Prevention of Significant Deterioration (PSD) permitting application process.

The Division is required to consider any FLM determinations that the proposed source would have an adverse impact on visibility in the Class I area (Regulation 3 Part D §V.A.6 and XIII.C). The Division may independently make its own determination. If the Division does determine that its own or the FLM's analysis demonstrates that an adverse impact would occur, the Division shall not issue the permit.

In addition to the analysis, a source may be required to conduct monitoring to establish the condition of, and impact on, air quality related values (AQRVs) in the Class I area that may be affected. Monitoring can be required both before completing a permit application to construct and during the construction and operation of the source (Regulation 3 Part D §VI.A.3, §VI.A.4, §XIII.B).

C. Consultation With Federal Land Managers.

Regulation No. 3 provides for participation by the FLMs in the new source review process. The FLMs may also make recommendations to the Division concerning integral vistas, identify impairment in any Class I area, and provide consultation concerning elements considered for inclusion in the monitoring strategy. The Division also is required to consult with the FLMs during development and review of the Phase I Long-Term Strategy (Regulation 3 Part D §XIV.F.1.a).

D. Monitoring Strategy.

The monitoring strategy in the SIP is based on the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual effects from the operation of new major sources or modifications to major sources on nearby Class I areas.

4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major sources must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permittees will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the FLMs or the Division certify existing impairment in a Class I area, the Division will determine if the documented visibility impairment can be reasonably attributed to emissions from an existing local stationary source. In making this determination, the Division will consider all available data, including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is not sufficient to make a decision regarding “reasonable attribution” of visibility impairment from an existing source(s), the Division will initiate cooperative studies. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

E. Phase I Long-Term Strategy.

The Phase I LTS is that portion of the Visibility SIP that is the State’s long-term strategy for making reasonable progress toward remedying existing and preventing future visibility impairment within the context of the Phase I program.

EPA regulations require the State to: (1) develop a long-term strategy; (2) coordinate its LTS with existing plans and goals, including those of federal land managers, that may affect impairment in any Class I area; (3) demonstrate why the LTS is adequate for making reasonable progress toward the national goal and state why the minimum factors (listed in the next paragraph) were or were not addressed in developing the LTS; (4) consider the time necessary for compliance as well as the economic, energy, and non-air quality environmental impacts of compliance, the remaining useful life of any affected existing source, as well as the effect of new sources; (5) review its strategy no less frequently than every 5 years and consult with federal land managers during this process; and (6) report to EPA and the public on progress achieved toward the national visibility goal.

During development of the LTS the State must consider, at a minimum, the following six factors:

- *Emission reductions due to ongoing air pollution control programs.* For example, the attainment and maintenance of National Ambient Air Quality Standards in the Denver metropolitan area and other non-attainment areas throughout Colorado may reduce visibility impairment in a number of Class I areas in the State. If this is the case, the State should explain how this would contribute to reasonable progress.
- *Additional emission limitations and schedules for compliance.* For example, states may have to control other sources causing impairment not covered by BART to make reasonable progress toward the national goal.
- *Measures to mitigate the impacts of construction activities.* This recognizes that nearby construction activities can contribute to impairment in Class I areas. If this appears to be a problem in Colorado, then the State should explain in its LTS what measures it will take to mitigate these impacts.
- *Source retirement and replacement schedules.* The construction of new sources, which will ensure the early or scheduled retirement of older, less well-controlled sources, can greatly aid progress toward the national visibility goal over the long term.
- *Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for this purpose.* The LTS should discuss measures that would constitute reasonable progress in relation to this issue.
- *Enforceability of emission limitations and control measures.* In some situations the enforceability of proposed or actual emission limitations and control measures on sources causing existing impairment may be an issue.

F. Colorado's LTS History and the Current Review and Revision.

Since the time the Colorado Visibility SIP was adopted by the AQCC in 1987, the LTS has been amended and/or reviewed on eight occasions:

- The original 1987 LTS was reviewed and revised in August 1992.
- After the 1993 certification of impairment at the Mt. Zirkel Wilderness Area, the EPA requested an informal LTS status report, which was supplied in December 1993.
- The 1996-97 LTS was completed in two stages:
 - August 1996 -- focusing entirely on the Mt. Zirkel Wilderness Area certification of impairment and the incorporation of emission limitations for the Hayden Generating Station; and
 - April 1997 -- addressing all other issues.

- The LTS was comprehensively reviewed again in January 1999, but a SIP revision was not found to be necessary.
- Following the Craig Consent Decree in early 2001, the LTS was again amended in April 2001 incorporating emission limitations, schedules, and reporting requirements for Craig Units 1 and 2. The State, the USFS, and EPA concluded that the 1993 certification of visibility impairment involving Mt. Zirkel Wilderness Area was resolved.^{2,3}
- The February 2002 LTS was comprehensively reviewed and the LTS portion of the SIP was updated and reorganized into a more readable format.
- The November 2004 LTS was also a comprehensive review and minor SIP revision update.

Past LTS reviews and SIP revisions are available from the Division.

This current review is a report on the activities, actions, processes, and progress made with respect to the seven review categories within the context of the existing Phase I LTS, adopted by the Commission in November 2004. Colorado believes, based on an assessment of the State's achievements with respect to these seven categories, that the current Reasonably Attributable Class I visibility program of the State of Colorado achieves reasonable progress toward the national visibility goal under Phase I of the visibility protection program.

In a separate document is a SIP revision to the reasonably attributable part of the LTS. The revision is a relatively small series of amendments intended to reflect current conditions and plans.

II. REVIEW OF COLORADO'S LONG-TERM STRATEGY

A. STATE AND EPA REQUIREMENTS

State regulations require the Division to periodically report to the AQCC on the progress made toward the national visibility goal via the Phase I SIP. This report to the AQCC and the public is being submitted to fulfill these requirements. A SIP revision is contained in a separate document.

EPA regulations require that the State provide this report to the public and the Administrator of EPA. Both EPA and State regulations require the report to include an assessment of:

1. The progress achieved in remedying existing impairment of visibility in any Class I area.
2. The ability of the long-term strategy to prevent future impairment of visibility in any Class I area.
3. Any change in visibility since the last such report, or in the case of the first report, since plan approval, including an assessment of existing conditions.
4. Additional measures, including the need for SIP revisions that may be necessary to ensure reasonable progress toward the national visibility goal.
5. The progress achieved in implementing BART and meeting other schedules set forth in the long-term strategy.
6. The impact of any exemption from BART granted to any facility.
7. The need for BART to remedy existing impairment in an integral vista declared since plan approval.

B. STEP-BY-STEP REVIEW

Each element of the review is presented in detail below.

1. PROGRESS IN REMEDYING EXISTING IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

The Phase I Class I Visibility SIP is focused on source-specific or plume-type impairment from single or small groups of stationary sources, consistent with Phase I of the implementation of EPA's visibility program.

a. Visibility Impacts in the Mt. Zirkel Wilderness.

In July 1993, the USFS certified visibility impairment in the Mt. Zirkel Wilderness Area and named the Hayden and Craig power stations as suspected sources.¹ As noted, upon certification by a federal land manager of visibility impairment in a Class I area, the Division must determine if it can "reasonably attribute" the visibility impairment to one or more existing stationary

sources. If so, the Division must conduct a BART analysis and as a result may order emission limitations for each pollutant at the facilities.

The Division considered existing information available at the time of the USFS certification of impairment to determine if it could make a decision to reasonably attribute visibility impairment within the MZWA to the Hayden and/or Craig generating stations. The Division concluded that existing information was insufficient to reasonably attribute. The Division's response was to collaboratively develop with other stakeholders the \$3.5 million Mt. Zirkel Visibility Study (MZVS) in order to collect additional information. The MZVS was concluded in July 1996.⁴

For a complete review of the activities, studies, and events that have occurred in relation to this environmental matter, see the April 1997 and January 1999 LTS reviews (available from the Division). Below is a summary of the how the certification of impairment has been resolved.

(i). Hayden Station.

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. On May 21, 1996, the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice executed an agreement -- the Hayden Consent Decree.⁵ On May 22, 1996, the Decree was filed in federal district court. The court approved it on August 19, 1996. The Decree was intended to resolve a number of issues, including a successful Sierra Club lawsuit against the Hayden Station, the needs of the State's visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC on August 15, 1996. The State believes that these significant emission reductions effectively eliminate the sulfate and primary plume related visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has concluded that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.⁶

The construction of Hayden's control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NO_x, SO₂, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit and the permit has been issued and the Consent Decree has been terminated.

(ii). Craig Generating Station (Yampa Project).

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999. After Hayden was

resolved in August 1996, attention turned to Craig Station Units 1 and 2. The Mt. Zirkel Visibility Study (MZVS) indicated to the Division that sulfate haze from Yampa Valley power plants occasionally entered the MZWA and along with regional haze contributed to visibility impairment. Thus, the focus to resolving the Craig Station portion of the certification was on reducing SO₂, the precursor pollutant of sulfate, from Craig Station Units 1 and 2. The State preferred to resolve the visibility certification through negotiated settlement. If settlement seemed unlikely, the State was prepared to resolve the certification using the available regulatory tools. At a meeting in late 1996 between the State, Craig Owners, and EPA, the State agreed to temporarily delay pursuing regulatory action in order to foster the collaboration needed to jointly develop additional information on various SO₂ emission reduction options and associated cost. Craig Station Units 1 and 2 at the time achieved 65% SO₂ control; both EPA and the State believed that an improvement in the degree of control would resolve the certification. A joint study, known as the Craig Station Flue Gas Desulfurization Study (Craig FGD Study), became the focus for a negotiated settlement. The information could also be used as part of a BART determination if needed. The study was completed in August 1999.⁷

There were other issues involved and parties concerned with emissions from Craig Station Units 1 and 2. The USFS has strong concerns about local emissions of SO₂ and NO_x that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. A 1996 Colorado statute provides FLMs with an opportunity to assert impairment to Class I areas by air pollution adversely affecting non-visibility related qualities of the area, such as the aquatic ecosystem.⁸ The USFS did not trigger the law with an assertion related to MZWA and was awaiting the outcome of the resolution of the visibility certification and/or global settlement of all issues. In addition, the Sierra Club initiated a citizen lawsuit under the Clean Air Act in late 1996 directed against Craig Station Units 1 and 2 regarding opacity issues.

In Fall 1999, the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. On September 22, 1999, EPA issued a SIP call to Colorado indicating the State had twelve months to resolve the certification regarding Craig Station Units 1 and 2.⁹ The Craig Owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. The court approved the agreement on March 19, 2001. The State resolved the certification of impairment for Units 1 and 2 of Craig Station by adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The USFS concluded that, “the proposed reductions of both sulfur dioxide and nitrogen oxides will resolve all Forest Service issues relative to the Craig Stations and our 1993 Certification of Impairment.”¹⁰ The SIP was amended by the AQCC on April 19, 2001² and EPA published final approval of the SIP amendment after a public comment period.³ Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NO_x, SO₂, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility’s Title V operating permit. The permit has been issued and the Consent Decree terminated.

(iii). Other Stationary Sources and the MZWA.

The Division has found no evidence that other stationary sources potentially subject to

BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA under Phase I of the EPA visibility program. The USFS certification of visibility impairment, related to the Phase I program, has been completely resolved. Regional haze that impacts any Colorado Class I areas, including MZWA, are addressed in the regional haze SIP.

(iv). Monitoring and the MZWA.

It is important to track the effect of the emission reductions at Hayden and Craig generating stations on visibility impairment near the Wilderness as well as on acid levels in sensitive lakes and the snowpack. Funding for and the collection of these data are provided variously by the USFS, U.S. Geological Survey, EPA, and the Division. Table 1 below provides a brief overview of monitoring activities in and around MZWA.

Table 1
Long-Term Visibility and Non-Visibility Air Quality Related Value Measurements
In and Near the Mt. Zirkel Wilderness Area

Instrument, Measurement, or Sampler	1. Sponsor 2. Funding 3. History	Purpose
Continuous SO ₂ monitor at Buffalo Pass Tower*	1. Colorado Air Pollution Control Division 2. \$9,800/year by CAPCD 3. 9/97 through present.	Measures frequency and magnitude of SO ₂ “hits” at Buffalo Pass as an indicator of the presence of Craig and Hayden emissions and potential impacts at the Mt. Zirkel Wilderness Area. The monitor provides hourly average SO ₂ . The purpose of the monitor is to determine whether trends are occurring as emissions change at Hayden and Craig 20 and 40 miles away, respectively, in the Yampa Valley.
Continuous ambient nephelometer at Buffalo Pass Tower*	1. US Forest Service 2. \$9,600/year by USFS 3. 1994 through present.	Measures frequency and magnitude of visibility episodes (the nephelometer measures light scattering, a component of visibility) at Buffalo Pass. This measurement provides hourly average light scattering but is subject to significant weather interferences.
Automatic camera system	1. US Forest Service 2. \$5,280/year by USFS 3. 10/90 through present	Three 35mm slides are taken each day and archived. The visual information can be used to document various types of visibility conditions and matched/collated with instrumental measurements.
IMPROVE aerosol monitor at Buffalo Pass Tower*	1. Initially USFS, now EPA, as part of the national IMPROVE visibility monitoring network. 2. \$14,000/year by EPA (for supplies and analysis) \$33,000/year by USFS (for support of all Buffalo Pass Tower monitoring operations)	Measurements include 1-in-3 day sampling, 24-hour filter based PM _{2.5} (chemically speciated) and PM ₁₀ (mass only). Light extinction reconstruction is calculated from the various aerosol constituents. Measurement of overall reconstructed light extinction is used for episode identification as well as trends. These reconstructed extinction data will be compared between the before and after periods. While this measure is not as prone to weather interferences as the nephelometer, other challenges in analyzing these data include changes in regional emissions, climatic variation, wildfire, and the nature

Instrument, Measurement, or Sampler	1. Sponsor 2. Funding 3. History	Purpose
	3. 1994 through present	of trying to distinguish episodic change in a 24-hour average.
National Acid Deposition Program (NADP) sampler at Buffalo Pass Tower*.	1. USFS 2. \$12,288/year by USFS 3. 1984 through present	Measurement of acid precipitation-related chemical constituents. The network collects data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).
Mercury deposition sampler at Buffalo Pass Tower*	1. USFS 2. \$12,000/year by USFS 3. 1997 through present	Mercury deposition sampling is done through the NADP program. This site is sponsored and funded by USFS. The purpose is to measure mercury deposition. The sample is collected weekly and sent to the NADP's Central Analytical Laboratory.
Snowpack chemistry sampling in March or April of each year prior to spring snowmelt.	1. USGS, NPS, USFS 2. \$115,000/year 3. 1990 through present	Annual measurement of snowpack chemistry prior to spring snowmelt and the release of acids during the "spring acid pulse." The U.S. Geological Survey has been monitoring snowpack chemistry at more than 50 locations throughout the Rocky Mountain region, extending from northern New Mexico to northern Montana, annually since 1993. There are 20 sites in Colorado, including several in and near the Mt. Zirkel Wilderness. Some sites in Colorado have been monitored since 1990. The purpose of the monitoring is to: 1) have an integrated measurement of acid deposition and snow chemistry over the snow accumulation months in high altitude areas associated with sensitive high altitude aquatic ecosystems; 2) determine whether trends are occurring in the snowpack chemistry; and 3) provide indicators of regional and/or local source emission changes.
Lake sampling in Mt. Zirkel Wilderness (and 2 other wilderness areas) during summer and fall.	1. USFS/CDPHE/ USGS 2. \$62,000 3. 1983 through present	Measurements of acid precipitation-related chemical constituents as well as overall measures such as hydrogen ion, pH, and buffering capacity of 3 lakes in the Mt. Zirkel Wilderness. The purpose of the long-term monitoring of these lakes is to: 1) determine the natural variance in chemistry of the lakes; 2) determine whether trends are occurring in the chemistry of lakes in the Mt. Zirkel Wilderness, and 3) provide information on the ambient chemistry of lakes in the Wilderness.

*Buffalo Pass monitoring tower is at the southern end of the Mt. Zirkel Wilderness.

The measurements provide a reasonably comprehensive network to track the emission changes

through different parts of key environmental systems, including atmospheric emissions, visibility, precipitation, acid deposition, mercury deposition, snowpack and aquatic ecosystems.

(v). Analysis of the Effects of the Hayden Generating Station Emission Reductions.

Using the data collected from the network described above, the Division and the USGS completed an analysis during 2004-2005 of the effects of the emission reductions at the Hayden Generating Station. At that time, Craig had just completed its emission capture upgrade and there were insufficient data to analyze to assess the additional effects of the Craig project. Therefore, the analysis focused on the reductions at the Hayden Generating Station. A final report will be completed during 2009 on the effects of the reductions at Craig as well as an assessment of the combined effect of the decreases in emissions from both facilities.

Study Design. Environmental data were compared between a period “before” Hayden was controlled versus a period “after” Hayden was controlled.

The period before controls were installed at Hayden is defined as 1995 through 9/24/98. 1995 is chosen as the beginning of the before period even though data extends earlier for a number of data sets. The before period is purposely constrained to limit the influence of regional emission changes over time as well as climate variation.

Unit 1’s boiler was brought down on 9/25/98 to begin the tying-in and integration of its various air pollution control systems. Unit 1 was re-started with emission controls on December 21, 1998. Unit 2’s boiler was brought down on 3/7/99. It was re-started on May 20, 1999. However, intermittent problems with the SO₂ controls could not be fixed until November 16, 1999. The Craig Generating Station (Yampa Project) began its upgrades on September 13, 2003. The three periods (i.e., before, during, after) are summarized in Table 2 below. Only the before and after periods were analyzed and compared.

Table 2
The Before, During and After Periods

Period	Dates	What
Before	1995 through 9/24/98	This is the period before Hayden’s pollution controls began operating
During (not analyzed)	9/25/98 through 11/16/99	Pollution control equipment was being tied-in, integrated and de-bugged.
After	11/17/99 through 9/12/03	Hayden’s equipment in routine operation and Craig had not yet begun its tie-in period.

Confounding Factors. Because the collection of environmental data occurs in the real world,

rather than in a laboratory where other changes can be held constant, there are several influences the data analysts were aware might confound or mask the signal of Hayden's emission change. All of the factors below contribute to make it more difficult to find and attribute the changes due solely to Hayden.

- Climate
 - The before period was wetter than average and the after period was drier than average. There was a 30-40% decrease in precipitation between the two periods depending on measurement location.
- Regional Haze
 - The after period was 17% more hazy. This is largely due to the decrease in precipitation and associated drought. Chemical analyses showed that almost all of the change between the two periods was due to particles from wildfires and increased dust.
- Overall Yampa Valley Emissions
 - Hayden and Craig are in the same valley, therefore, emissions from both must be considered together since analysis techniques can't identify the pollutants from one plant versus the other. Given Hayden's specific reduction and the ongoing operation at Craig (before its upgrade), SO₂ decreased in the Yampa Valley by 48% and NO_x increased 7%.
- Regional Emission Changes
 - Not only was there an emission change at Hayden, but large emission reductions of SO₂ also occurred in the southwestern part of the U.S. For example: Arizona/39%, New Mexico/27%, Wyoming/18%, Texas/15%.
- Atmospheric Chemistry
 - The atmospheric chemistry converting invisible SO₂ gas to visible sulfate particles is not linear. That is, a one unit decrease in SO₂ may not lead to a one unit decrease in sulfate.

Results.

- Emissions
 - Sulfur dioxide (SO₂) removal at Hayden has always been at least 85% over 30 and 90 day rolling averages since the compliance period began. Nitrogen oxides (NO_x) have decreased approximately 50% annually. The new particulate control system has completely eliminated the occasional black smoke-plume episodes that previously occurred.
- Ambient SO₂ as measured at Mt. Zirkel Wilderness Area
 - Decreased 40% due to the reductions at Hayden.
- Haze at Mt. Zirkel Wilderness Area
 - Increased 17% due to the drought and increases in regional haze. This would have been worse without the reductions at Hayden.
- Sulfate Particulate Haze
 - Overall decrease of 20% at Mt. Zirkel Wilderness Area.
 - Peak sulfate episodes were eliminated in the after data. This is a very important finding because it is the worst days that hamper enjoyment of clear visibility.

- It is estimated that approximately half of the overall decrease is due to Hayden's reductions. The other half is due to the regional scale reductions in SO₂.
- Acid Deposition Measurements
 - Decrease in sulfuric acid deposition of approximately 20%.
 - Looking at other measurement sites, this decrease in sulfuric acid *only* occurred at acid deposition sites downwind of Hayden.
 - Overall decrease in acid deposition at all sites, however, most of this is drought related due to an increase in dust elements in the rain and snow that buffer acids.
- Snowpits
 - Small decrease in sulfuric acid at pits downwind from Hayden.
 - Overall decrease in acidity, again due to more dust elements in the snowpack.
- Lakes
 - No change due to emission reductions in before versus after periods. This is expected because response time to an emission reduction of SO₂ in a watershed is several years. Effects of drought were also visible in lake acidity (i.e., less acid due to increased dust elements).

In spite of the big challenges nature and other anthropogenic changes piled onto the study design, the USGS and the APCD see a strong signal decrease in episodic visibility impairing sulfate and acidic wet sulfate in and near the Mt. Zirkel Wilderness Area from the emission reductions at Hayden Generating Station.

b. Regional haze.

EPA published its final regional haze rule in July 1999.¹¹ This review of the Phase I SIP is not related formally to the regional haze program. Nevertheless, such haze exists at all Colorado Class I areas and is the subject of the larger regional haze SIP document within which this LTS review is embedded and coordinated.

c. Ongoing Air Pollution Control Programs.

Since the November 2004 LTS review/report several activities in ongoing air pollution control programs have occurred that are relevant to this review.

(i). Rocky Mountain National Park Initiative.

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Through these efforts significant amounts of data have been collected. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

Two-thirds of the Park is near or above treeline with shallow soils and granitic bedrock that are indicative of a fragile ecosystem environment. This environment is highly susceptible to changes induced by chemical contributions to soils and waters through atmospheric deposition. The Park's enabling legislation and other key Congressional statutes mandate that natural resources at RMNP are to remain unimpaired for future generations. Thus, the Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and ozone by the Early Action Compact and SIP development process.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative's progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP works to: (1) consider all available emission reduction options and programs for nitrogen-related emissions (primarily nitrogen oxides (NO_x) and ammonia (NH₃)); (2) provide a technical assessment of the state-of-knowledge of deposition components and trends, the emission sources, source areas, and atmospheric transport; (3) determine implementation measures for making progress and mechanisms to evaluate effectiveness of, and incorporation of new, control measures; (4) make recommendations for future needs as necessary to assure continued progress and achievement of Park goals; and (5) incorporate adaptive management principals for the consideration and use of new data and analyses as they become available.

The Plan includes a critical load determination for nitrogen affecting the high alpine ecosystems in the Park that was established prior to the development of this Plan. The critical load for wet nitrogen deposition, set at 1.5 kg/ha/yr, is a threshold value above which significant harmful effects to sensitive ecosystem components occur. The critical load for wet nitrogen deposition east of the Continental Divide in RMNP represents an estimation of the concentration at which excess nitrogen deposition began causing harmful impacts on RMNP ecosystems. The Plan relies on a "glidepath" management approach to achieve the critical load goal in the Park by

the year 2032 with interim milestones to be measured at five-year intervals. The first milestone, set for 2012, works to achieve a reduction that is consistent with an average rate of deposition reduction that will achieve the critical load by the year 2032 and reflects the potential benefit from planned state and federal emission reduction programs.

The NDRP was approved by the AQCC in April 2007. Implementation of the Plan will likely benefit visibility at RMNP to an unknown degree. The Division maintains a website that is a clearinghouse for information related to the Initiative. The full NDRP and other technical documents may be found at

<http://www.cdphe.state.co.us/ap/rmnp.html>

(ii). The Four Corners Task Force.

After many years of concern about emissions growth in the Four Corners area and impacts on nearby Class I areas, the States of New Mexico and Colorado have convened an Air Quality Task Force to work on the air quality issues and challenges facing the Four Corners region. The Four Corners region is rich in coal and oil & gas reserves. Oil & gas production and coal-fired power plants result in large emissions of air pollution that may be degrading air quality. Specific concerns include National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increment compliance, degradation of visibility, and increased deposition.

The U.S. Department of Interior - Bureau of Land Management (BLM) and the U.S. Department of Agriculture - Forest Service (USFS) are currently responding to industry proposals for expanded development of oil and gas production in the region. There are two proposed coal-fired power plants: a 1,500 megawatt plant proposed on Navajo Nation lands and a 300 megawatt plant proposed north of Grants, New Mexico. Additionally, the population in the Four Corners region likely will continue to grow in coming years, resulting in even more air pollution and, specifically, more nitrogen oxide emissions.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to begin to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning.

The Task Force work groups are:

- Oil and Gas,
- Power Plants,
- Other Sources,
- Cumulative Effects, and
- Monitoring.

These workgroups are studying issues and creating lists of options to the Task Force about how to proceed. An executive/steering committee that includes representatives from the states of

Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables are being developed to ensure that all options developed are timely. The task force will work over a two-year period and deliver a final report by December 2007.

The Task Force's website is

<http://www.nmenv.state.nm.us/aqb/4C/index.html>

(iii). New Oil and Gas Controls.

On December 17, 2006, the Colorado Air Quality Control Commission (AQCC) adopted changes to oil & gas industry regulations to reduce emissions of volatile organic compounds (VOCs) from condensate tanks. VOCs are a precursor to ozone formation and secondary organic carbon particulate – a component of visibility degradation.

New control requirements were established for condensate tanks in both the Front Range Early Action Compact Area and statewide. New reporting and recordkeeping requirements were also established. The new requirements are summarized below:

Control Requirements: Front Range Ozone Early Action Compact (EAC) Area

- Commencing May 1, 2007, companies in the EAC region must increase the control of VOCs from current 47.5 percent level to 75 percent for the summertime ozone season.
- In addition, there are new reporting and recordkeeping requirements.

Control Requirements: Statewide

- Tanks standards: New and existing condensate tanks emitting 20 tons per year or more of VOCs required to control emissions by 95 percent commencing May 1, 2008.
- Glycol Dehydrator controls: New and existing glycol dehydrators emitting more than 15 tons per year of VOCs are required to control emissions by 90 percent commencing May 1, 2008.
- Table 3 contains engine standards for new or relocated engines from out-of-state commencing July 1, 2007.

Table 3
Engine Standards

Maximum engine horsepower	Construction or relocation date	NOx g/hp-hr	CO g/hp-hr	NMHC g/hp-hr
100 - 500 hp	January 1, 2008	2.0	4.0	1.0
	January 1, 2011	1.0	2.0	0.7
Greater than 500 hp	July 1, 2007	2.0	4.0	1.0
	July 1, 2010	1.0	2.0	0.7

Additional information about the new emission controls can be found at <http://www.cdphe.state.co.us/ap/oilgas.html>

(iv). Review of Ongoing Programs and Status of Redesignations.

The most comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2006-2007 Report to the Public. This report in its entirety is included as Attachment 1.

As recently as 1995 Colorado had 12 "non-attainment" areas within the State for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas has also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA has designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 8-hour ozone, though the nonattainment designation has been deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone on Friday, July 20, 2007 appear to have put the nine-county Denver region in violation of the federal health-based, eight-hour standard for ozone. If monitoring results are verified, the region will likely be designated as "nonattainment" for ozone by the U.S. Environmental Protection Agency. A detailed plan to reduce ozone will be developed for submission to the EPA in 2008 by the Colorado Air Pollution Control Division, along with the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization. This new plan, a federally -required State Implementation Plan for ozone, will require further reductions in ozone levels beyond what was required through an earlier Ozone Early Action Compact.

The table below shows the designation status for Colorado non-attainment areas as of April 2007.

Table 4
REDESIGNATION and PLAN AMENDMENT STATUS REPORT – 4/2/07

	<u>Redesignations</u>	<u>Plan Amendments</u>
PM10		
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	None
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	None
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved

	<u>Redesignations</u>	<u>Plan Amendments</u>
		12/15/05; Governor submitted to EPA 9/25/06
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	None
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	None
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	None

Carbon Monoxide		
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	
Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06

Ozone		
Denver /Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; Governor submitted to EPA 10/06 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg 7 oil and gas condensate tank and engine requirements. Governor's submittal anticipated -Additional exceedances in 2007. SIP preparation in 2008.
Lead		
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide		
Denver	EPA redesignated Denver attainment in 1984	

2. THE ABILITY OF THE LONG-TERM STRATEGY TO PREVENT FUTURE IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

Generally, the State of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as meeting the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities. In addition, there are specific activities the Division has undertaken.

a. Modeling Guidance.

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division's expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division's web site at: <http://apcd.state.co.us/permits/cmng.html>

b. Smoke Management.

Colorado believes its smoke management program is protective of public health and welfare as well as Class I visibility. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. The program is described below.

(i). Regulation No. 9.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. In addition to its permitting requirements, it implements Colorado Senate Bill 01-214 (“Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Therefor”) that became law in 2001. The regulation also incorporates permitting and reporting requirements for all users of prescribed fire similar to those in the State’s past Smoke Management Memorandum of Understanding (MOU). The AQCC adopted the regulation on January 17, 2002.

Regulation No. 9 is in eight sections:

- I. Scope
- II. Definitions
- III. Open Burning Permit Requirement
- IV. General Open Burning Permits
- V. Planned Ignition Fire Permits
- VI. Unplanned Ignition Fire Permits
- VII. Additional Requirements for Significant Users of Prescribed Fire
- VIII. Fees

The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement.

After the scope and definitions sections, the rule has several sections regarding permitting and other requirements applicable to open burning of various types. Section IV contains requirements for a general open burning permit and associated permit conditions. Sections V and VI contain the permitting, information, modeling and reporting requirements, as well as a smoke risk categorization, and permit conditions for planned ignition prescribed fires to insure that prescribed fires neither violate National Ambient Air Quality Standards nor have unacceptable visibility impacts. These provisions are similar to the past voluntary agreements among signatories of the expired Colorado Smoke Management MOU for prescribed fire. The regulation, however, applies to all users of prescribed fire above a de minimus level project. The rule also specifies requirements regarding suppression of prescribed fire if monitoring and/or air pollution levels indicate that permit conditions, the burn prescription, and/or air quality standards have been or will be exceeded. The Division’s draft permits for large burns with a high smoke-risk are subject to a 30-day public comment period and the opportunity for a public comment hearing before the Commission. The Division will disclose potential visibility impacts of these proposed fires and must consider comments when determining whether to grant, conditionally grant, or deny the final permit.

Sections VII and VIII are the elements of the regulation that implement SB01-214. Section VII addresses how significant users of prescribed fire (i.e., those that own or manage 10,000 acres and generate at least 10 tons of PM₁₀ annually from use of prescribed fire) must submit planning documents to the Commission. The regulation identifies the contents of the planning documents. The rule further requires that all such prescribed fire activities of significant users

shall conform to the State standard to “minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable.” SB 01-214 directs the Commission to hold a public hearing regarding each planning document and to develop any necessary comments and recommendations to bring the plans into consistency with the State goal. After July 1, 2002 the Division cannot issue open burning permits to significant users for lands whose planning documents and fuel management decision-making are inconsistent with Commission recommendations and comments. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, the Forbes/Trinchera Ranch, and the Denver Water Board.

Fees are discussed in section VIII. No fees are charged for general permits (local authorities may charge fees under their own authority). Significant users of prescribed fire pay fees of \$59.98/hour to the Division for review of planning documents. Prescribed fire permittees pay for the cost of the prescribed fire program based on a cost distribution methodology. The Division’s Fiscal Officer calculated the cost of the program at the outset of the program beginning in calendar year 2002. The Statement of Basis, Specific Statutory Authority and Purpose of the regulation also specifies the Commission’s intent that the Division annually calculate the cost to administer the program and report to the Commission each August on program costs, projections, and revenues. If the cumulative cost varies more than 5% from the total fee amount in regulation, the Division will seek a fee change before the Commission in a properly noticed public hearing. In addition, the Statement indicates that any deficits not be funded by stationary source fees. The current cost of the program as stated in Regulation No. 9 is \$174,585.08.

While not included in the rule, it is important to note that the statute also finds the prescribed fires of significant users conducted on lands the primary purpose of which is nonagricultural to be for “commercial purposes”. The effect is to subject any such activity conducted without a permit to significantly higher fines than previously (i.e., up to \$100/day for “noncommercial purposes” and up to \$10,000/day for “commercial purposes”).

In March 2004, the Commission approved changes to Regulation No. 9 allowing the permitting of Air Curtain Destructors (ACD) to be used for the narrow purpose of burning wildland fuels generated as a result of projects to reduce the risk of wildfire. The use of ACDs in lieu of pile burning will significantly reduce emissions from defensible space and other types of wildfire risk reduction projects.

(ii). The Regulation and Visibility Protection.

Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. For example,

- the potential contribution of such burning to air pollution in the area;

- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;
- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
 - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
 - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
 - a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permittees to submit an application to the Division. Proposed planned ignition burns are compared to computer model output that indicates the air pollution (including visibility) impacts. A permit is granted only if the modeling run demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides that the Division may impose “permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare.”

Permittees are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permittees must indicate whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2006 are available by contacting the Division.

As mentioned above, the regulation requires that the draft permit for any proposed prescribed fire rated as having a “high” smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division’s web site contains information about the various aspects of Colorado’s Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. The web site underwent a major revision and updating during 2005. It is located at: <http://www.cdphe.state.co.us/ap/smoke/>

3. CHANGES IN VISIBILITY SINCE SIP APPROVAL AND ASSESSMENT OF EXISTING CONDITIONS

Visibility monitoring is being performed in or near a number of Colorado’s Class I areas.

The specific purposes of monitoring may vary, but generally include assessing existing conditions and trends as well as learning more about the sources of visibility impairment in Colorado's Class I areas.

The routine visibility monitoring performed in Colorado's Class I areas are at IMPROVE, IMPROVE Protocol or IMPROVE Look Alike sites. IMPROVE is an acronym that stands for Interagency Monitoring of PROtected Visual Environments. IMPROVE is a cooperative visibility monitoring effort of the EPA, NPS, USF&WS, BLM, USFS, Western States Air Resources Council (WESTAR), Mid-Atlantic Regional Air Management Association (MARAMA), North Eastern States for Coordinated Air Use Management (NESCAUM), and the National Association of Clean Air Agencies (NAACA). IMPROVE Protocol sites are operated using the same equipment, procedures and analytical labs as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE Look Alike sites are operated using the same equipment and procedures but may utilize different labs. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by a sponsoring federal land management agency or state. IMPROVE Look Alike sites may be funded by private industry or other entity. IMPROVE and IMPROVE Protocol sites are operated by the NPS, BLM, or the USFS. The State of Colorado has funded a short-term IMPROVE Look Alike site but does not fund other IMPROVE or IMPROVE Protocol sites. IMPROVE has an extensive web site at: <http://vista.cira.colostate.edu/improve>. Graphically processed IMPROVE data as well as links to photographic images of various haze levels at Class I areas and meteorological data are found on the Visibility Information Exchange Web System (VIEWS) at: <http://vista.cira.colostate.edu/views/>

The types of visibility monitoring being performed in Colorado's Class I areas and some of the results of this monitoring are summarized later in this section of the LTS review. The section is divided into three major parts:

- a. Monitoring Methods and Network -- a very brief discussion of each of the types of routine visibility monitoring performed in Colorado and a description of the monitoring network in place as of December 2006.
- b. Site-By-Site Data Summaries -- summaries of the routine data available as of April 2007 collected by these methods, a short discussion of the data, and of possible data trends of each site (park or wilderness area).
- c. Overall Conclusions from the Routine Monitoring -- statements about visibility levels, sources, and trends in Colorado's Class I areas.

a. Monitoring Methods and the Network.

Routine visibility monitoring consists of three general components. The first, view monitoring, is used to document the visual quality of a scene. The second component, atmospheric optical monitoring, measures basic optical properties of the atmosphere (e.g., atmospheric extinction, light scattering) that relate to the atmosphere's ability to cause visibility impairment. In some of Colorado's Class I areas atmospheric extinction has been directly

measured with a transmissometer. At one of the monitoring sites, a nephelometer monitors the scattering coefficient of ambient air. The third component of most routine visibility monitoring systems, particle monitoring, measures fine atmospheric particles that are responsible for visibility impairment. This third component is considered the core method for IMPROVE and at each site, at a minimum, is a chemically speciated fine particle monitor. Each general component of monitoring is described in more detail below.

(i). View Monitoring.

Camera systems are used to document visibility in a view from a fixed location. A specially constructed camera system automatically takes slides or digital images of a view at regularly scheduled times each day (usually three times per day). The images provide a qualitative record of visibility conditions that exist at a site.

Automated camera systems are in place at the following sites to monitor visibility conditions in or near the following Class I areas (the letters in parentheses below are how each site is referenced within the FLM and IMPROVE data and image management systems):

- Shamrock Mines (SHMI) near the Weminuche Wilderness;
- Maroon Bells-Snowmass Wilderness site in the White River National Forest (MABE); and
- Mt. Zirkel Wilderness (ZIRK).

In the past automated camera systems operated at the following sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Colorado National Monument (COLM);
- Dinosaur National Monument (DINO);
- Great Sand Dunes National Park (GRSA);
- Mesa Verde National Park (MEVE);
- Rocky Mountain National Park (ROMO);
- West Elk Wilderness (WEEL);
- La Garita Wilderness (LAGA);
- Eagles Nest Wilderness (EANE); and
- Weminuche Wilderness (WEMI).

In addition, camera systems have monitored at the following Class II wilderness areas:

- Lost Creek Wilderness (at the Devil's Head Fire Tower) (DEHE); and
- Mount Massive Wilderness (MOMA).

Once a multi-year visual record of site conditions is collected, the camera systems are removed and installed to document conditions at another site. A spectrum of various visibility conditions seen on the slides taken at a given site and relationship to other monitoring if

available are archived onto a photo CD and/or uploaded to web sites. Images are available at: <http://www.fsvisimages.com/> and http://vista.cira.colostate.edu/views/Web/IMPROVE/Data_IMPRPhot.htm

(ii). Atmospheric Optical Monitoring.

Atmospheric extinction describes the ability of particles and gases in the atmosphere to attenuate light over a given distance (e.g., per kilometer). Extinction occurs due to the scattering and absorption of light from gaseous and aerosol constituents of the atmosphere. A transmissometer is an optical visibility monitoring device, which can continuously measure atmospheric extinction. The instrument accomplishes the measurement by sending a light beam of known intensity to a distant receiver and measuring the resulting loss of light. A nephelometer directly measures the scattering component of atmospheric extinction.

High relative humidity, rain and fog events reduce visibility. Data collected during periods experiencing such events are often excluded from transmissometer and nephelometer data in order that it reflect anthropogenic influences. Transmissometer data were collected at the following IMPROVE sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Mesa Verde National Park (MEVE), through May 1993; and
- Rocky Mountain National Park (ROMO), through October 2006.

Nephelometer data are collected at:

- Mt. Zirkel Wilderness (MOZI).

(iii). Particle Monitoring.

Atmospheric particle monitoring is accomplished by a combination of particle sampling and sample analysis. Simultaneous particulate samples are collected in the four channels of the IMPROVE Particle Sampler: three PM_{2.5} samples (particles less than 2.5 microns in diameter) on different filter types (Teflon, nylon, and quartz) and one PM₁₀ sample (particles less than 10 microns in diameter) on a Teflon filter. The filters are subsequently analyzed for total mass, elements, organic and light absorbing carbon, ions, and optical absorption. Particulate monitoring is used to quantify and identify the air pollutants responsible for visibility degradation. Atmospheric extinction can be mathematically reconstructed from these chemically speciated aerosol samples – this is the core method EPA has selected for monitoring haze. Typically, an IMPROVE Sampler takes a 24-hour sample once every three days. The IMPROVE web site contains literature that indicates¹² the overall uncertainty (defined as the ratio of the mean precision from all sources divided by the mean concentration) is 4% to 7% for most variables and >15% for organic carbon. These numbers reflect precision; accuracy is unknown.

Particulate monitoring with an IMPROVE Sampler is performed in or near the following

Colorado Class I areas (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Great Sand Dunes National Monument (GRSA).
- Mesa Verde National Park (MEVE).
- Weminuche Wilderness Area (WEMI).
 - This monitoring site also represents visibility conditions in La Garita Wilderness and Black Canyon of the Gunnison Wilderness.
- Shamrock Mines (SHMI).
 - This site was installed in 2005 and is a supplemental site for assessing impacts to the Weminuche Wilderness Area from emissions activity in the Four Corners Area.
- Snowmass/Maroon Bells Wilderness site in the White River National Forest (WHRI).
 - This monitoring site also represents visibility conditions in West Elk Wilderness, Eagles Nest Wilderness, and Flat Tops Wilderness.
- Mount Zirkel Wilderness Area (MOZI).
 - This site also represents visibility conditions in the Rawah Wilderness.
- Rocky Mountain National Park (ROMO).
- Ripple Creek Pass (RICR).
 - This site is to the north of the Flat Tops Wilderness. It is funded privately by Shell Oil Company and operated by Air Sciences, Incorporated.
- Douglas Pass (DOPA).
 - This site operated at the top of Douglas Pass near the Utah border for over 2 years. It was funded by the Colorado Governor's Office of Energy Management and Conservation and operated by Air Sciences, Incorporated.

b. Routine Monitoring Data Summary.

A number of the visibility monitoring sites in Colorado's Class I areas have been in operation for several years. Table 5 below is a summary of the types of monitoring and the dates when monitoring has occurred at each of the sites.

Table 5
Routine Visibility Monitoring

SITE	CAMERA	TRANSMIS -SOMETER	NEPHELO- METER	IMPROVE PARTICULATE MONITORING	SITE TYPE¹
BLCA Black Canyon NP	2/85-11/93				BLM - IMPROVE PROTOCOL
COLM Colorado NM	7/81-9/91				NPS – IMPROVE PROTOCOL
COLP Louisiana- Pacific	7/92-1/97				NPS - IMPROVE PROTOCOL
DEHE Devil's Head Fire Tower Lost Creek WA	5/94-1/02				USFS- IMPROVE PROTOCOL
DINO Dinosaur NM	9/79-2/81 6/85-9/91				NPS- IMPROVE PROTOCOL
DOPA Douglas Pass				9/03-1/06	Colorado- IMPROVE Look Alike
EANE Eagle's Nest WA	6/93-9/00				USFS- IMPROVE PROTOCOL
GRSA Great Sand Dunes NP	7/87-4/95			5/88-present	NPS - IMPROVE
LAGA La Garita WA	9/97-10/01				USFS- IMPROVE PROTOCOL

¹ IMPROVE Protocol sites are operated using the same equipment and procedures as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by the sponsoring federal land management agency or state. Sites are operated by the NPS, BLM, or the USFS.

SITE	CAMERA	TRANSMIS -SOMETER	NEPHELO- METER	IMPROVE PARTICULATE MONITORING	SITE TYPE¹
MEVE Mesa Verde NP	9/79-4/95	9/88-7/93		3/88-present	NPS - IMPROVE
MOMA Mt. Massive WA	7/97-11/01				USFS - IMPROVE
MOZI Mt. Zirkel WA	10/90- present (on Storm Peak)		12/93-present	12/93-present	USFS - IMPROVE
RICR Ripple Creek Pass Flat Tops WA				12/02-present	Shell Oil- IMPROVE Look Alike
ROMO Rocky Mtn. NP	10/85-1/95	12/87-10/06		10/87-present	NPS - IMPROVE
SHMI Shamrock Mines Weminuche WA	11/05- present				USFS – IMPROVE PROTOCOL
WEEL West Elk WA	7/92-11/96				USFS - IMPROVE PROTOCOL
WEMI Weminuche WA	7/86-8/93			3/88-present	USFS - IMPROVE
WHRI/ MABE Maroon Bells/ Snowmass WA	12/91- present			7/93-9/99 (channel A only) 9/99- (full IMPROVE)	USFS – IMPROVE PROTOCOL USFS – IMPROVE

In 2003, two temporary sites were installed in Western Colorado. The sites use IMPROVE protocols and equipment but are unable to utilize one of the analytical laboratories under contract

to the long-term sites. As such, these temporary sites are known as IMPROVE Look Alike sites. One is at the north end of the Flat Tops Wilderness at Ripple Creek Pass and is funded by Shell Exploration and Production Company. The other was to the west of the first site nearly on the border with Utah at Douglas Pass. It has been discontinued. This site was funded by the Colorado Governor's Office of Energy Management and Conservation. The sites were installed and operated by a consulting firm, Air Sciences, Incorporated. The Division has provided technical support and advice as needed. As data are processed from these sites, they are uploaded to the VIEWS site annually. Data analysis from these sites are included in the Regional Haze SIP Technical Support Documents (TSDs).

A new IMPROVE protocol site has recently (Fall 2005) been added to the network within Colorado by the USFS. The Shamrock Mines site near Vallecito and the Weminuche Wilderness is intended to supplement the existing Weminuche Wilderness site. Shamrock Mines is at a much lower altitude than the current site. NO_x and ozone are also monitored at the new site. The USFS is concerned with the cumulative impacts of oil and gas development in the 4-corners region and believes the new location will better capture pollutants in the area.

For IMPROVE and IMPROVE Protocol sites in Colorado the camera, transmissometer, and nephelometer based data are collected, analyzed, and archived by Air Resource Specialists, Inc. (ARS), the contractor to IMPROVE, NPS, USFS and BLM for optical data. The particle data are collected, analyzed and archived by the University of California at Davis, the contractor to IMPROVE, NPS, USFS and BLM for particle measurements. For the IMPROVE Look Alike sites, Air Sciences, Inc. operates the sites and uses the same lab except for the University of California at Davis. Instead, RTI, Inc. is utilized. For all sites, the raw data may be downloaded from the IMPROVE or VIEWS web sites.

c. Site-By-Site Data Summaries.

Due to the extensive data analyses and displays within the Technical Support Documents and other sections of the Regional Haze SIP submittal, this LTS Review's focus is solely on trends at sites with more than 3 years of data. Trends in the haze index, known as deciview (dv) are provided for both the Best 20% days each year and Worst 20% days each year. These plots have been copied from the VIEWS web site. An additional focus is on the data since the last LTS Review in 2004.

(i). Mesa Verde National Park.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Mesa Verde National Park. Figure 1 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no particular trend but are not degrading. The Worst Days appear to have an overall steady increase in impairment beginning in 1992 through 2000. 2001 is the lowest year on record and 2002/2003 are the worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 2 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 2 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mesa Verde. Nitrate shows an increasing trend beginning around 1999 and continuing through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend over the years.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mesa Verde with no particular trend but demonstrates more variability beginning in 2000.

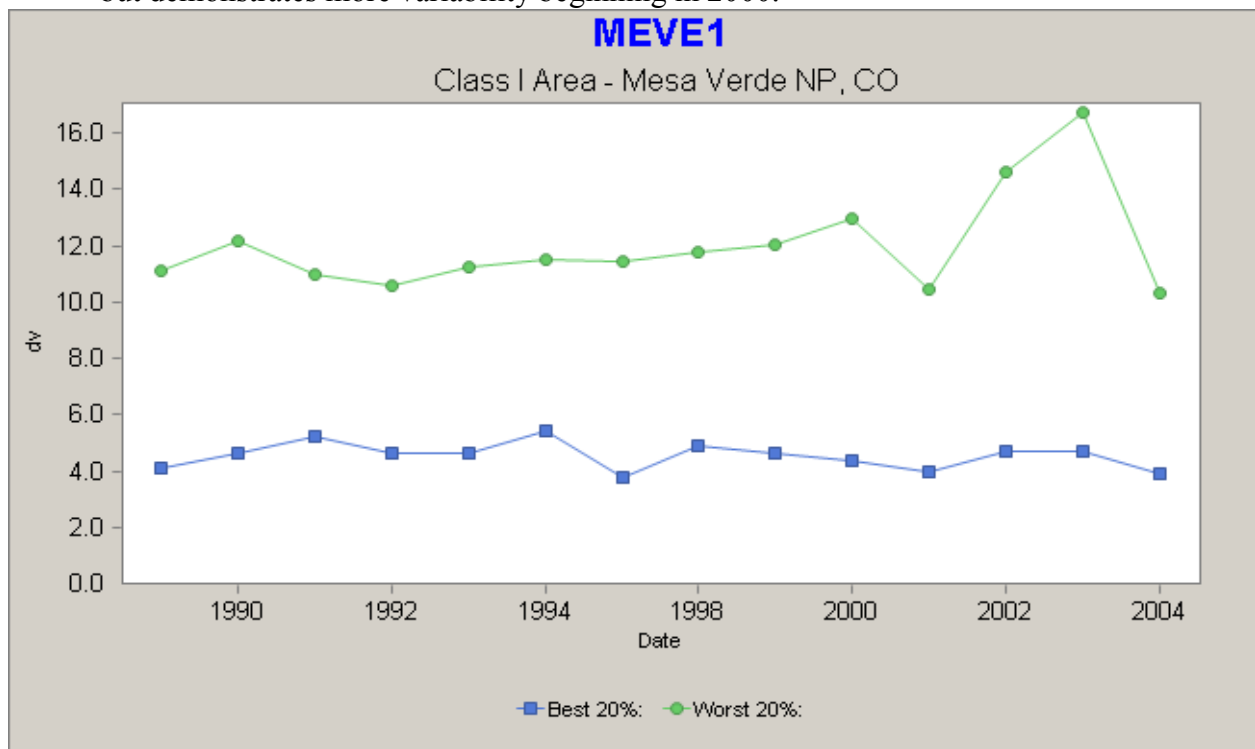


Figure 1: Mesa Verde National Park, Best and Worst Days, 1989 through 2004

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Mesa Verde, it starts fairly high early in the record then drops and begins a slow increase until 2000. Beginning in 2000, there is a period of “ups and downs” corresponding to the period of drought and wildfire in the West. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Mesa Verde NP.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values early in the record at the Park with increases corresponding to the drought period.

The influence of drought and related emissions from wildfire and dust events is evident. Figure 3 examines precipitation at Mesa Verde National Park from 1990-1997 versus 1998-2004. Average precipitation is around 6 inches lower in the more recent period and several years (1999-2002) have annual averages between 11.6 and 13.8 inches, reflecting the profound drought in the area.

(ii). Weminuche Wilderness Area.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Weminuche Wilderness Area. Figure 5 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show no degradation and a steady trend toward less impairment. The Worst Days appear to have a slight increase in impairment beginning in 1993 through 2000. 2001 is the lowest year on record and 2002/2003 are the 3rd and 4th worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 6 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 6 by pollutant shows that:

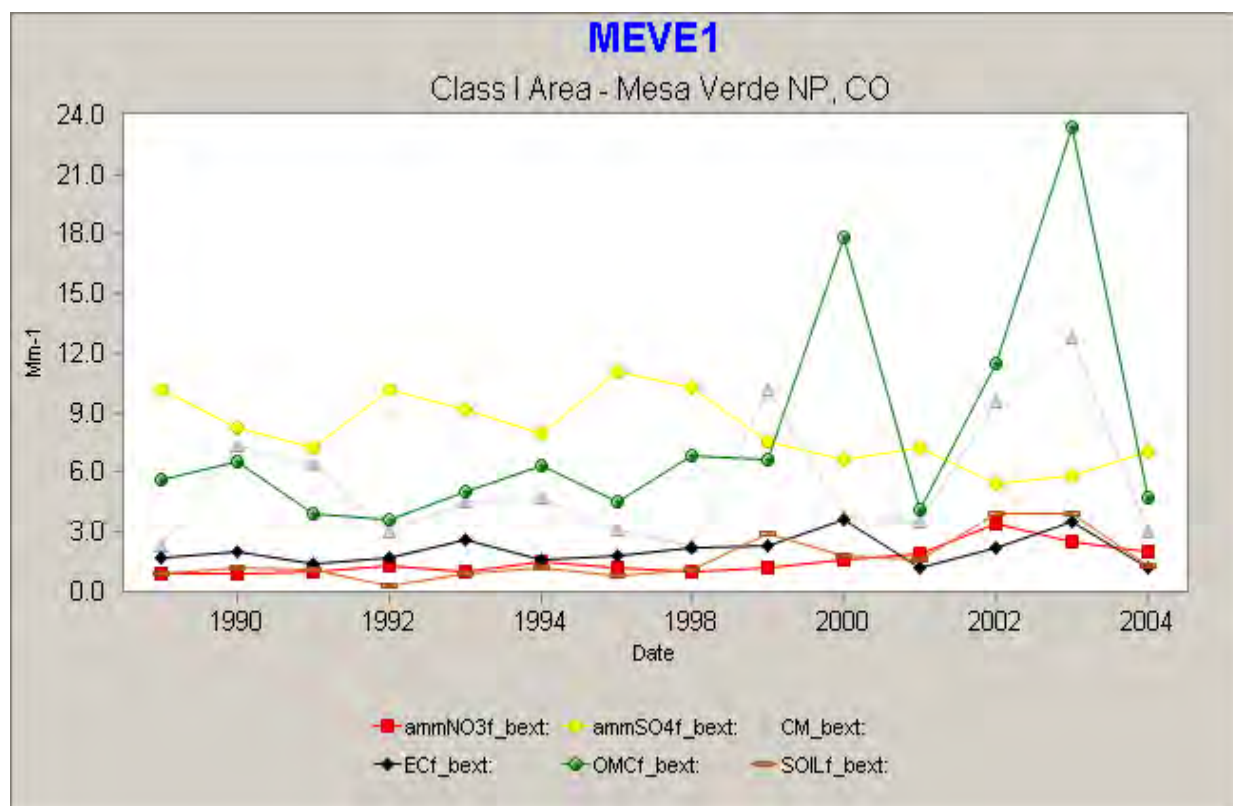


Figure 2: Mesa Verde National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

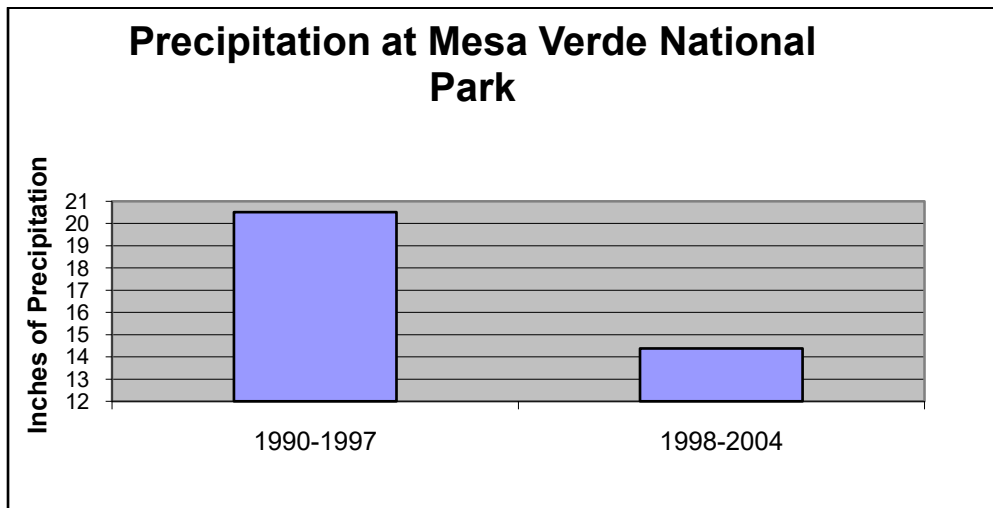


Figure 3: Precipitation At Mesa Verde National Park, 1990-1997 vs 1998-2004

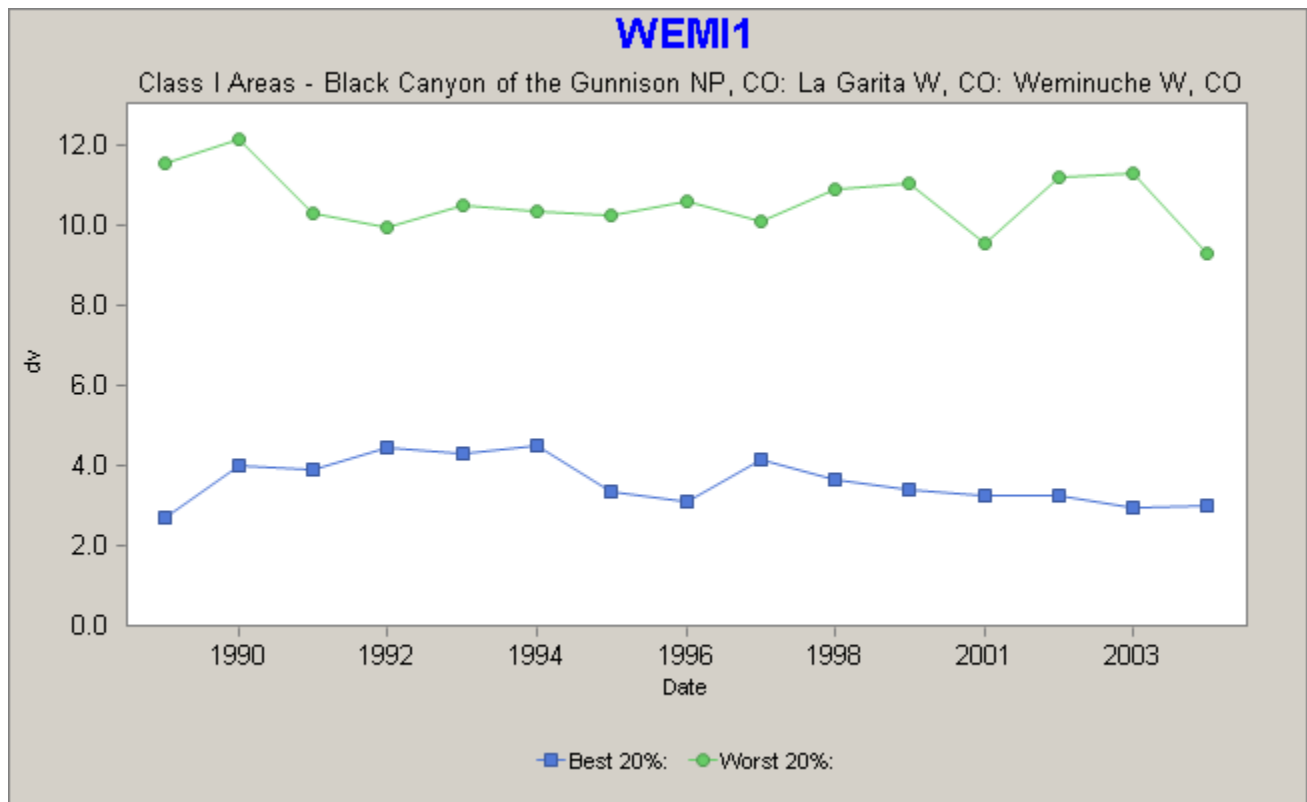


Figure 5: Weminuche Wilderness Area, Best and Worst Days 1989 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Weminuche. Nitrate shows an increasing trend beginning around 1997 and continuing through 2003. The 2004 value is less than recent years and is similar to what was measured in 2001.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a moderate contributor at Weminuche with a slight shift to lower values beginning in 1997.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Weminuche, it starts fairly high early in the record then drops and begins a slow increase until 2001. Beginning in 2001, there is a period of large variability corresponding to the period of drought and wildfire in the West and particular fires near and in the Weminuche Wilderness. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Weminuche.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period.

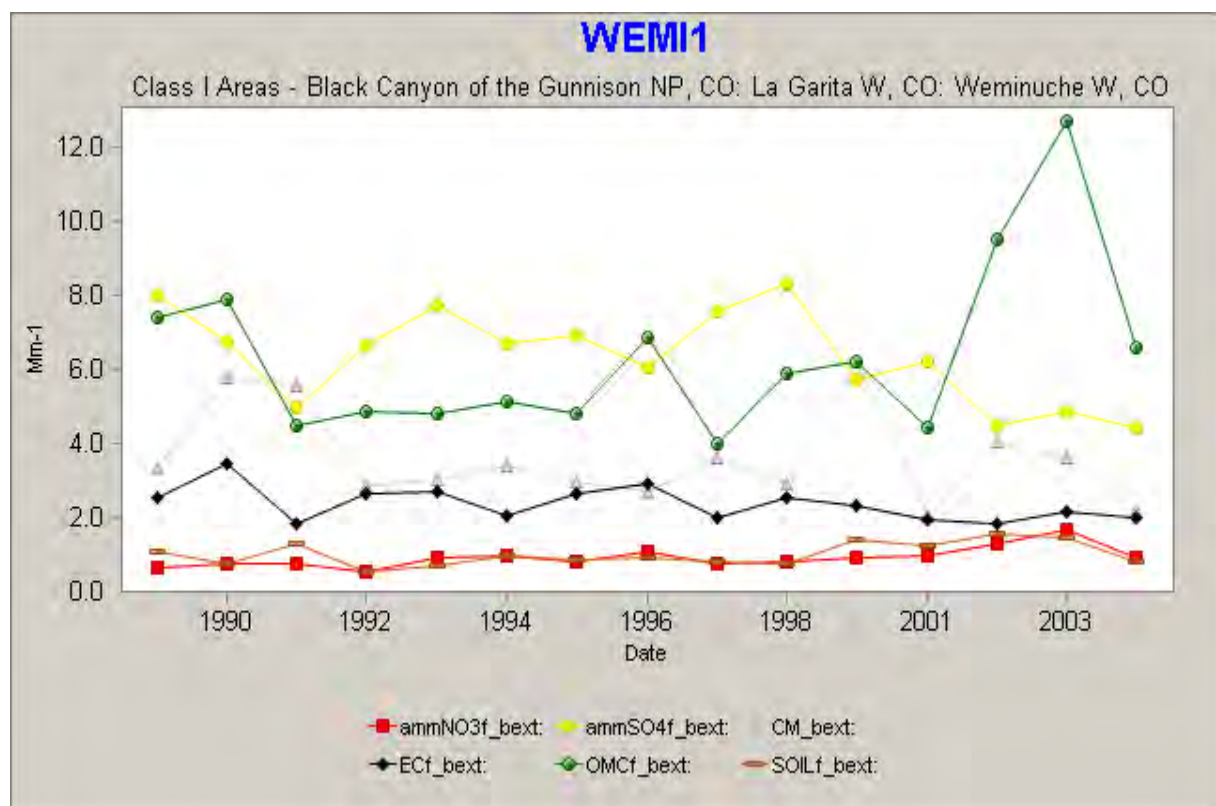


Figure 6: Weminuche Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(iii). Great Sand Dunes National Park.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Great Sand Dunes National Park. Figure 7 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show a little change and overall no degradation since 1999. The Worst Days appear to have a slight increase in impairment beginning in 1996 through 2000. 2001 is among the lowest years on record, followed by 2002: the highest on record. 2003 is the 4th worst and 2004 again returns to low values similar to 2001 and among the lowest on record. To explore these trends and the recent extreme variability further, Figure 8 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 8 by pollutant shows that:

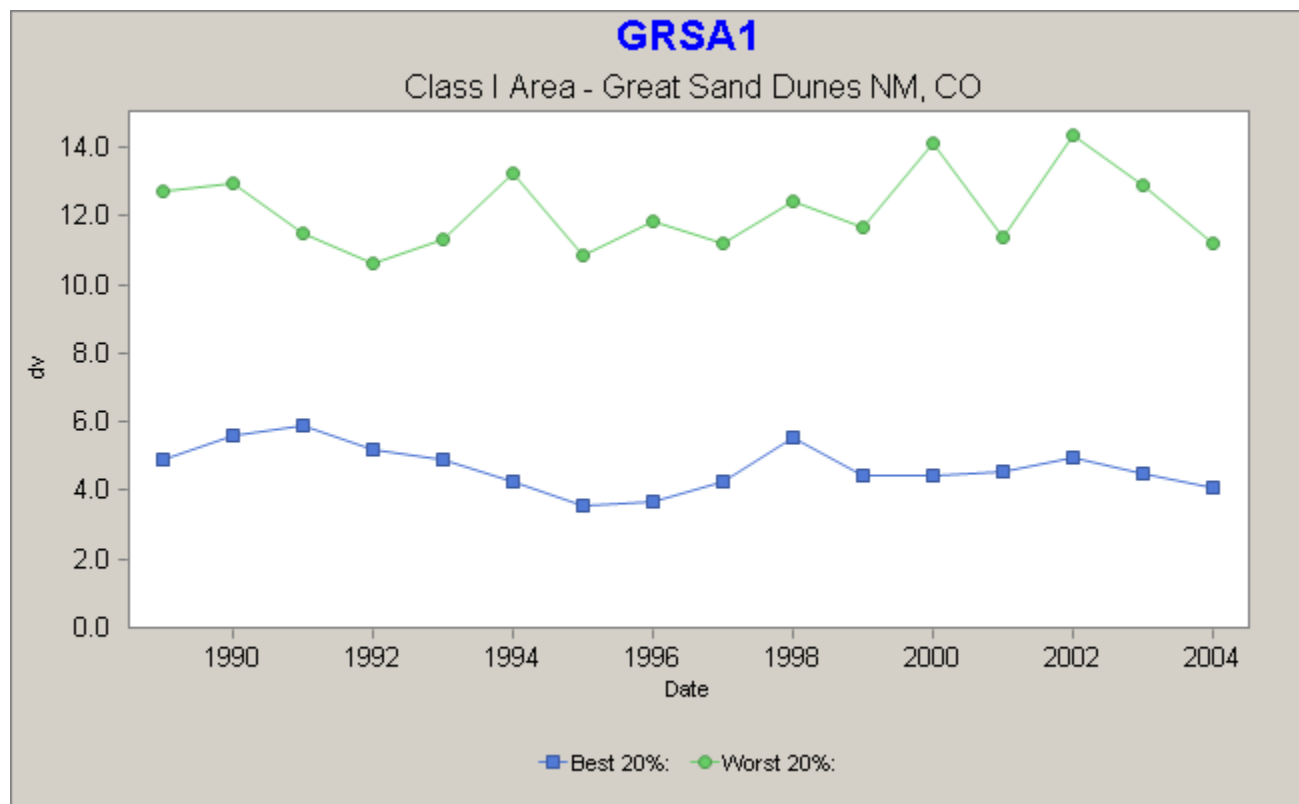


Figure 7: Great Sand Dunes National Park, Best and Worst Days 1989 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Great Sand Dunes. Nitrate shows a slight increasing trend beginning around 2000 and continuing through 2004, with a dramatic exception in 2003 (among the lowest values on record). The 2004 value is the highest on record.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a major contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Coarse mass shows a huge amount of variability

over its record with the “ups and downs” tracking closely with Organic Carbon in recent years.

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Great Sand Dunes NP with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Great Sand Dunes, it begins an “up and down” pattern in 1995 thru 2003. The pattern is broken by 2004 as its value continues in 2003’s declining direction.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period. Fine soil, coarse mass and organic carbon emerge in recent years as the most important contributors to impairment and variability in impairment at Sand Dunes.

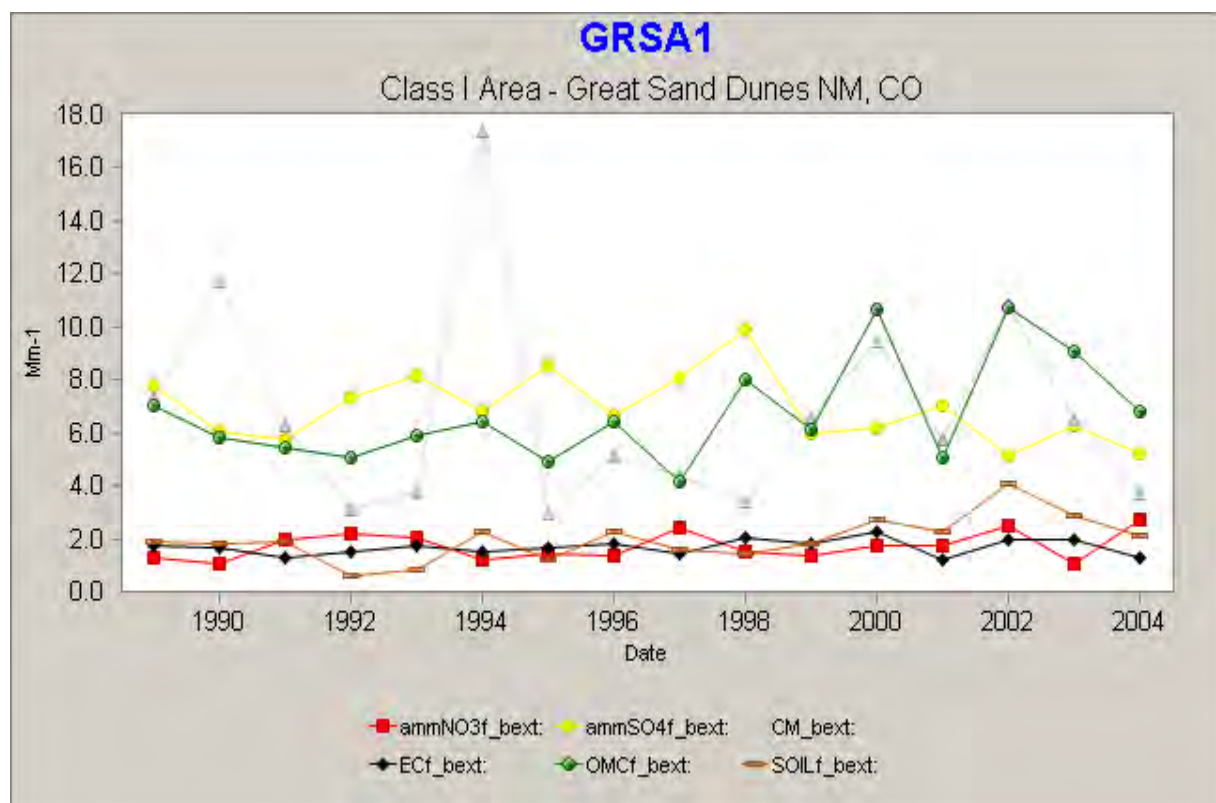


Figure 8: Great Sand Dunes National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(iv). White River National Forest - Maroon Bells/Snowmass Wilderness.

Processed IMPROVE Sampler data are available beginning in 2001 through 2004 at the White River site. Figure 9 presents annual average deciview for the best and worst days for each year of available data at the site. All other IMPROVE sites in Colorado have much longer data records, in most cases over 15 years. However, the White River site was installed during 2000, with the first complete data year in 2001. Based on the

four years of processed data, White River is Colorado's least impaired site compared to other IMPROVE locations in the state.

The Best Days show a no degradation trend over the four years of data. The Worst Days spike-up in 2002 but return to the 2001 value in 2003 and decline further in 2004. To explore these trends, Figure 10 contains a speciated look at the Worst Days from 1981 through 2004. A qualitative summary of Figure 10 by pollutant shows that:

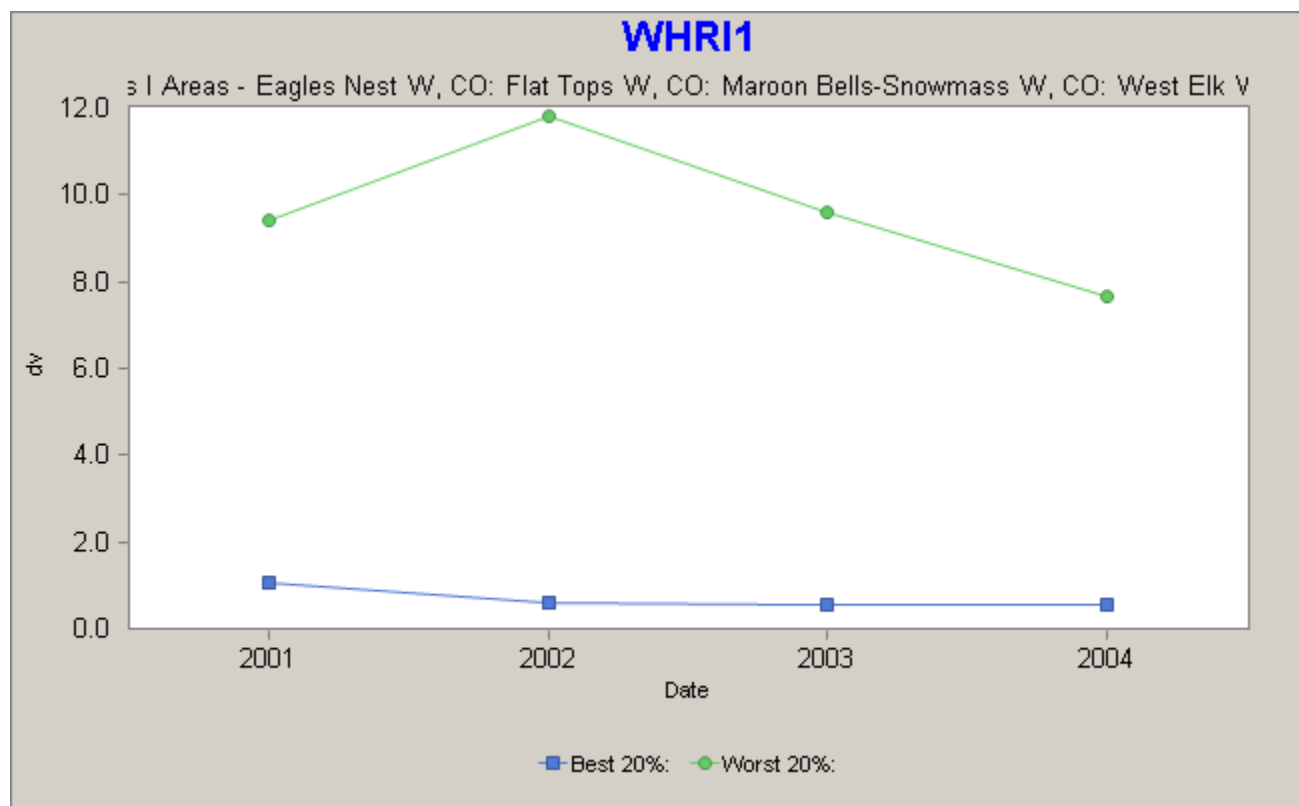


Figure 9: White River National Forest, Best and Worst Days 2001 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at the White River site. Nitrate shows a slight decreasing trend through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a moderate contributor at the White River site. Sulfate shows an overall decreasing trend.
- CM_bext (coarse mass extinction) is fairly moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to other sites in Colorado examined previously, there has been little relative variability in coarse mass and it declined in 2003 and 2004.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at the wilderness areas represented by the White River site and has had only a small amount of variability in the four years monitored.

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Organic carbon is a moderate contributor at White River, with the exception of 2002 when it spiked (likely due to upwind wildfire) and influenced impairment at the site more than the sum of the other pollutants combined.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

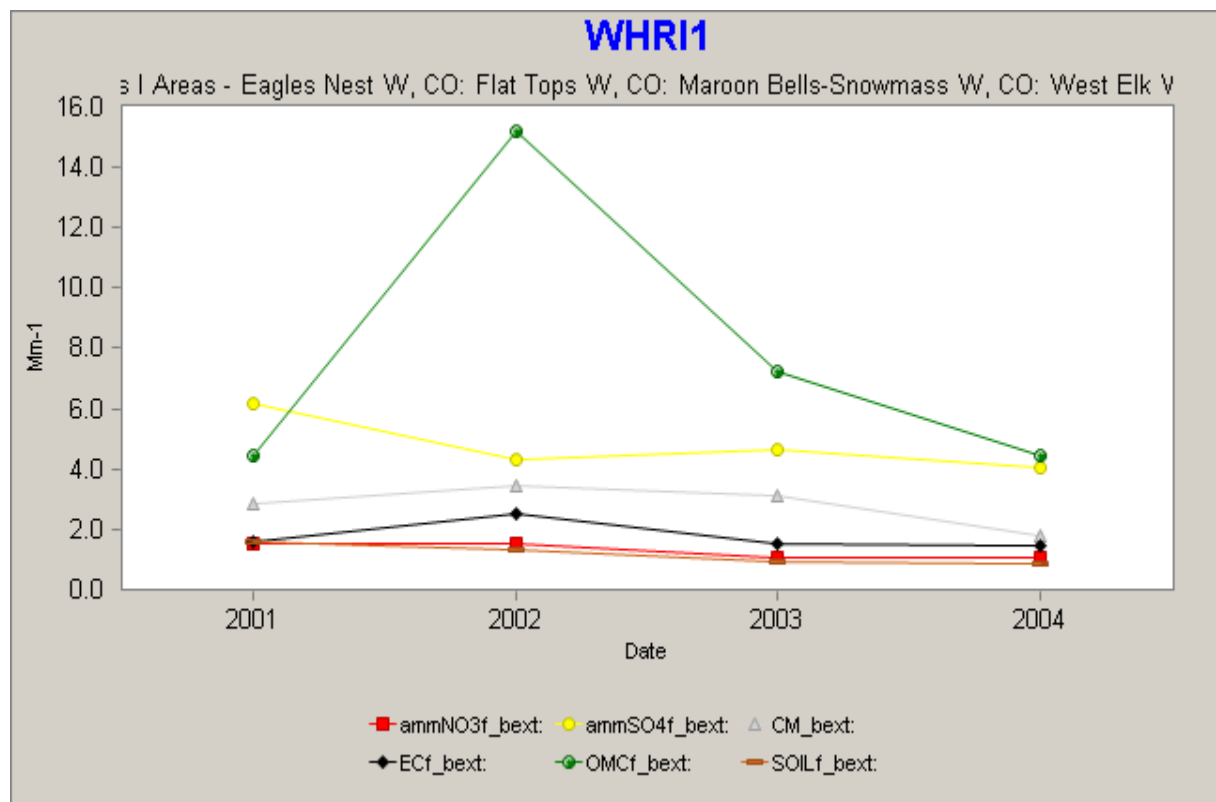


Figure 10: White River National Forest, Annual Extinction Values by Aerosol Species, Worst Days 2001 through 2004

(v). Mt Zirkel Wilderness Area.

Processed IMPROVE Sampler data are available beginning in 1995 through 2004 at Mt. Zirkel Wilderness Area. Figure 11 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show a no degradation trend over the 9 years of data (2000 was incomplete) with a fairly dramatic decline in impairment in recent years. The Worst Days do not exhibit any obvious trend; however, 2004 was the lowest on record. To explore these data further, Figure 12 contains a speciated look at the Worst Days from 1995 through 2004. A qualitative summary of Figure 12 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mt. Zirkel Wilderness Area. In recent years nitrate has increased and appears to be a moderate level contributor.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to the more southern sites, coarse mass at Mt. Zirkel shows little variability over its record and an overall declining trend.

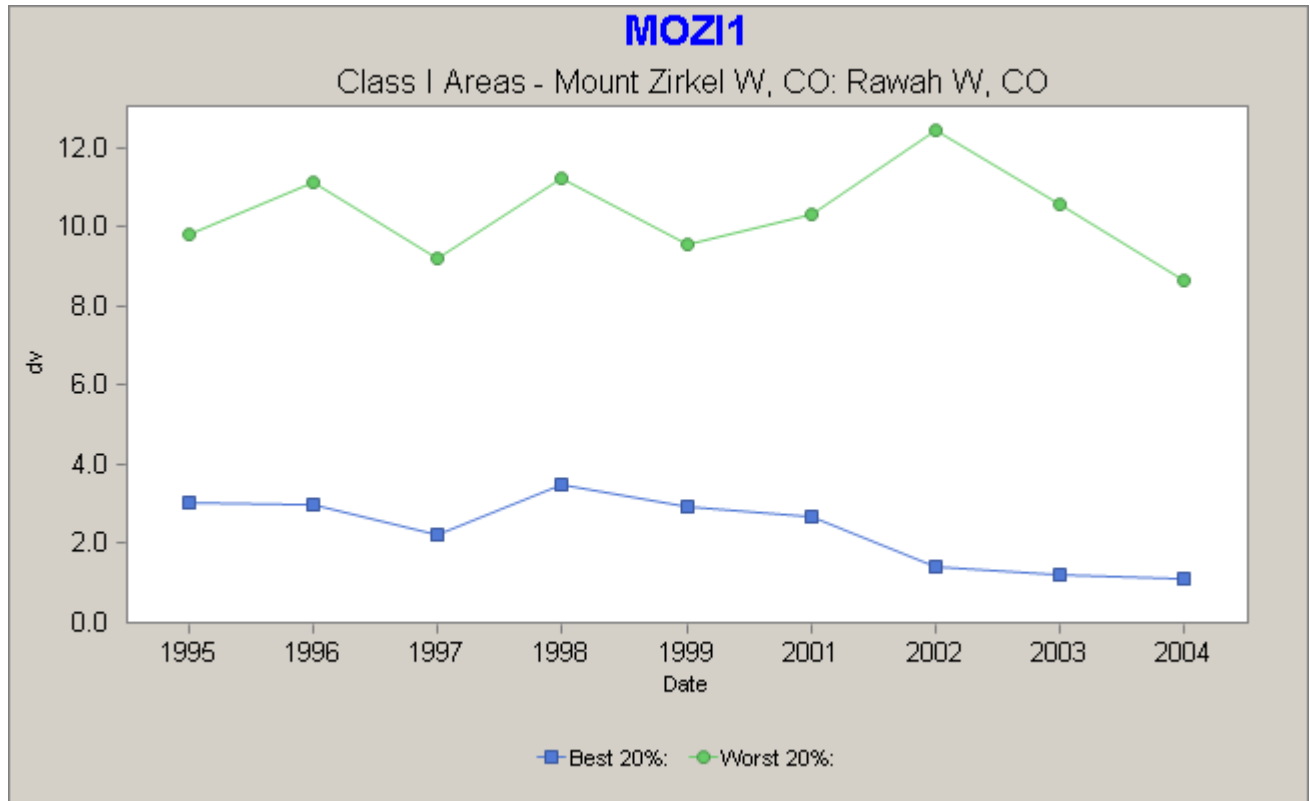


Figure 11: Mt. Zirkel Wilderness Area, Best and Worst Days 1995 through 2004

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mt. Zirkel Wilderness Area with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire) and a major contributor to impairment at this site. Over the period of monitoring at Mt. Zirkel Wilderness, organic carbon exhibits considerable variability and, similar to most other Colorado sites, had large annual worst day values for 2002 and 2003.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

(vi). Rocky Mountain National Park.

Processed IMPROVE Sampler data are available beginning in 1991 through 2004 at Rocky Mountain National Park. Figure 13 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no degradation over time and a trend toward less impairment. The most recent years are the cleanest on record. The Worst Days reflect the drought and shift up from 2000 through 2003. To explore these trends and the recent increase on the Worst Days further, Figure 14 contains a speciated look at the Worst Days from 1991 through 2004. A qualitative

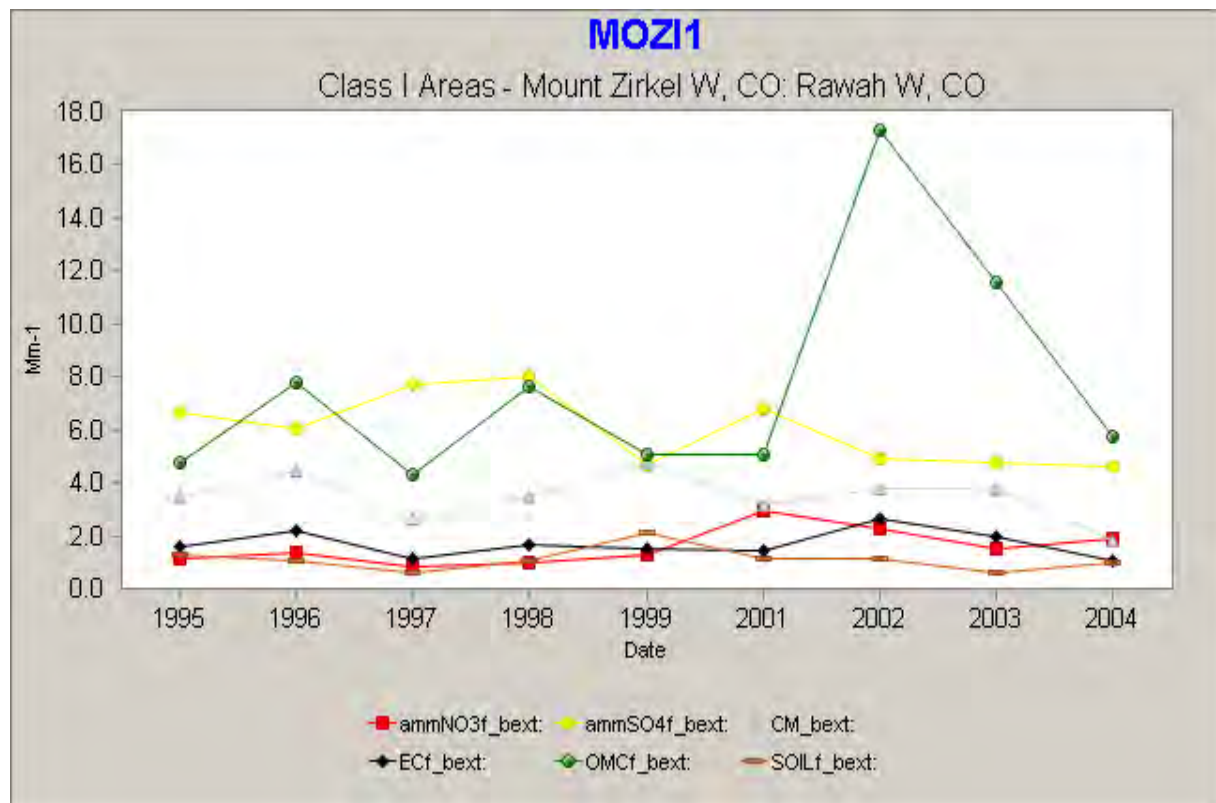


Figure 12: Mt. Zirkel Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1995 through 2004

summary of Figure 14 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and shifts from a moderate contributor to visibility impairment at Rocky to a major contributor in 2001 and 2002. Values for 2003 and 2004 drop to more typical levels. Nitrate shows a decreasing trend from the beginning of the record through 2000 then the two-year spike occurs. Rocky Mountain National Park's nitrate levels are higher overall than other IMPROVE sites in Colorado. The two-year spike is unusual given that nitrate is largely an anthropogenic pollutant.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. In contrast with other IMPROVE sites in Colorado, sulfate does not demonstrate an obvious declining trend over the data record. However, considering the period 1999 through 2004, there are 4 of the 5 lowest values in the data record. Similar to what was seen for nitrate, the sulfate spike in 2001 and 2002 may need further exploration.

- CM_bext (coarse mass extinction) is a moderate contributor. In 2000, it spiked and for that single year it was a major contributor, along with organic carbon. Coarse mass emissions mostly consist of natural sources (e.g., wind blown dust). Coarse mass does not reveal an obvious trend over the record and there is a lesser reflection, compared to

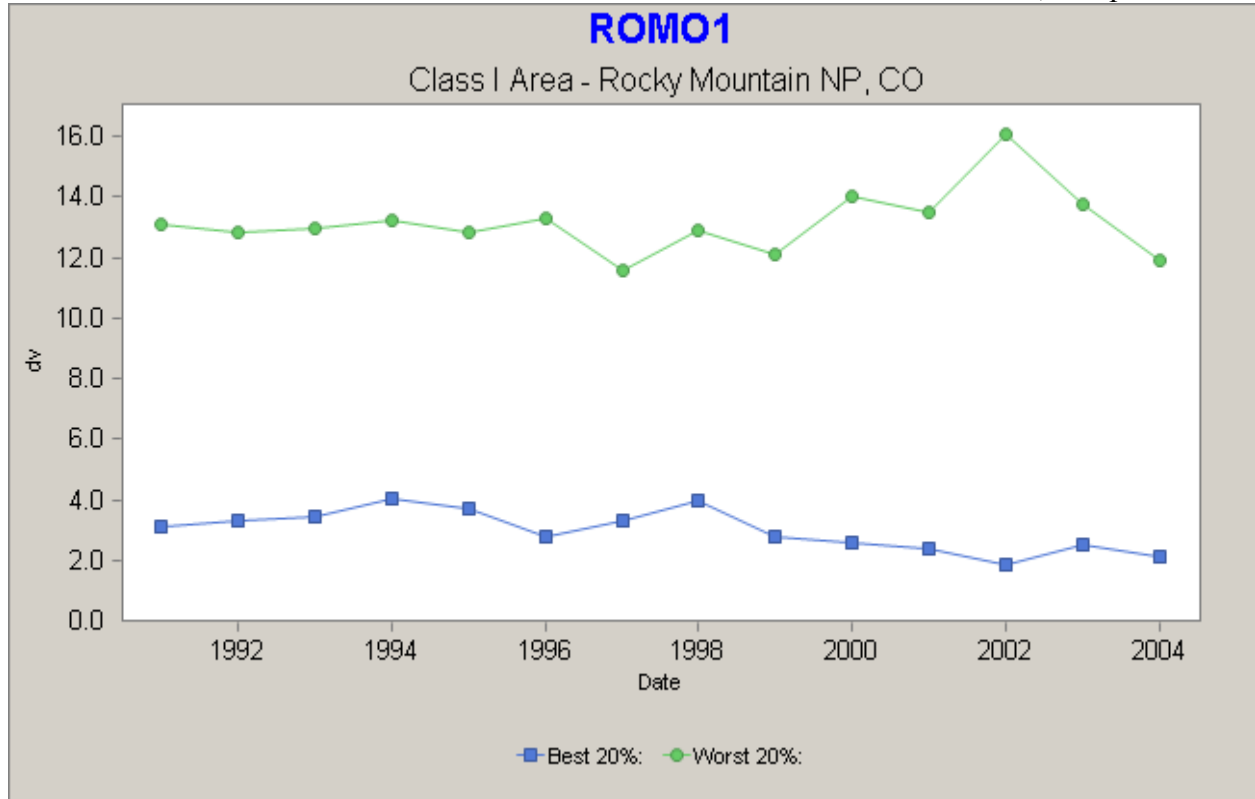


Figure 13: Rocky Mountain National Park, Best and Worst Days 1991 through 2004

many other sites in Colorado, of the drought in recent years.

- ECf_bext (elemental carbon extinction) is both an anthropogenic (e.g., diesel emissions) and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Rocky Mountain NP with no particular trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Rocky Mountain National Park, the “ups and downs” seen at other sites also have occurred at Rocky as well as the large values during the peak drought years.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with low values throughout the record at the Park.

In order to explore further the unusual nitrate and sulfate levels in 2001 and 2002, additional plots are presented below from the VIEWS website. They are the 2000, 2001 and 2002 annual composition plots for Rocky Mountain National Park. Each stacked bar represents a 24-hour sample. Each bar component is one of the species listed on the plot legend. The “W” over a bar means that sample is among the worst 20% impaired during that year. A “B” over a bar indicates that sample is in the 20% best visibility days during that year. Figure 15 is 2000 data.

This is a fairly typical year for sulfate and nitrate at Rocky. There are no combined sulfate and nitrate episodes above 20/Mm-1 of extinction. Figure 16 is 2001 data. There are 9 sample days with combined sulfate and nitrate above 20/Mm-1. Figure 17 is 2002 data. There appear to be 7 or 8

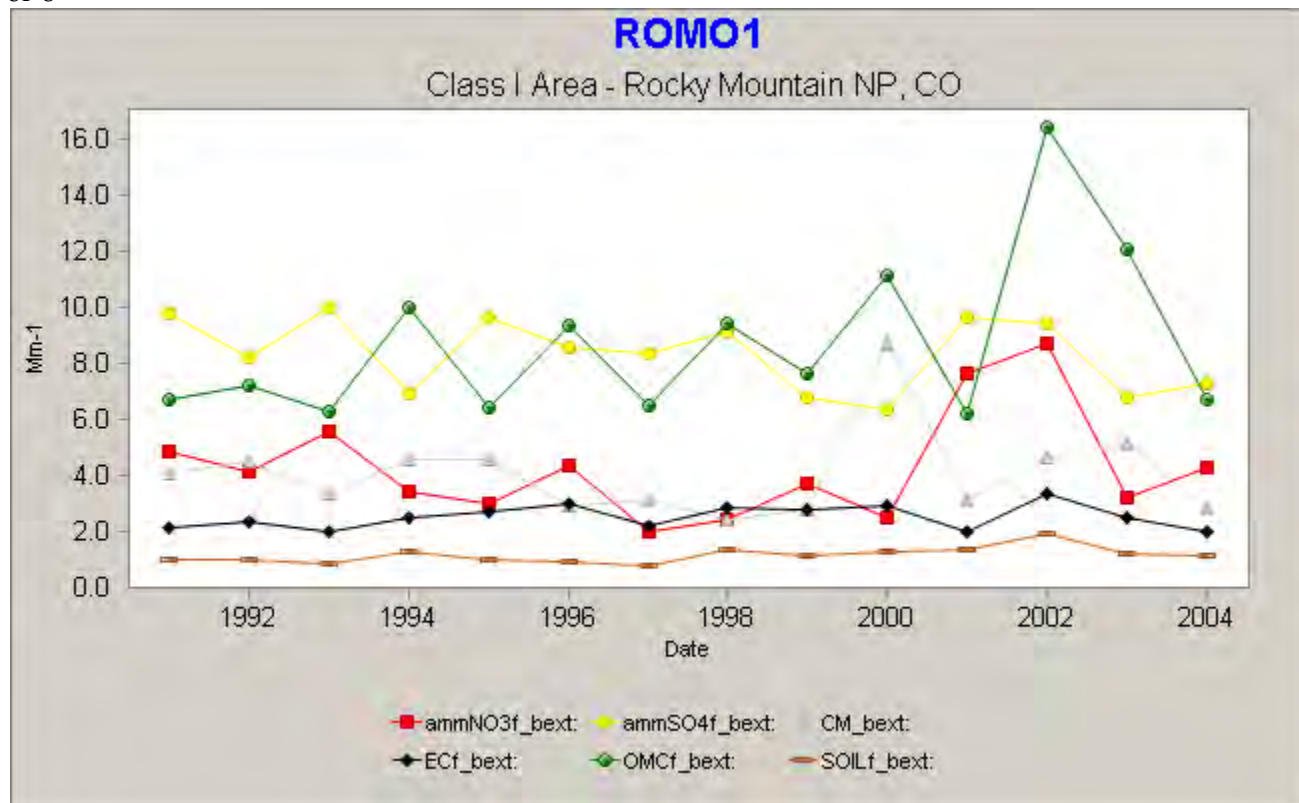


Figure 14: Rocky Mountain National Park, Annual Extinction Values by Aerosol Species, Worst Days 1991 through 2004

such days in 2002. It is important to note that these episodes, with 1 or 2 minor exceptions, do not occur when other pollutants are also peaking. The Division is hopeful that results from the ROMANS study, conducted by the National Park Service to examine nitrogen and sulfate emissions and precursors at Rocky Mountain National Park, will provide some insight about the sources and meteorological conditions that occurred in 2001 and 2002 that led to the 7-9 peaks of sulfate and nitrate per year. For more information about the ROMANS study see <http://www.cira.colostate.edu/publications/newsletter/fall2006.pdf>

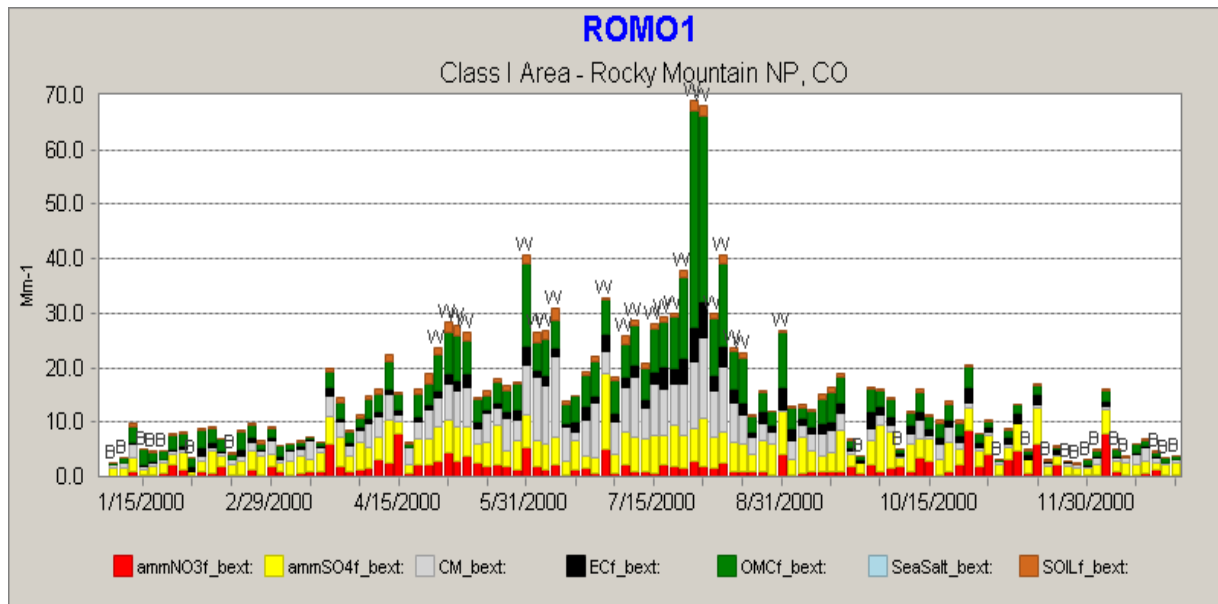


Figure 15: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2000

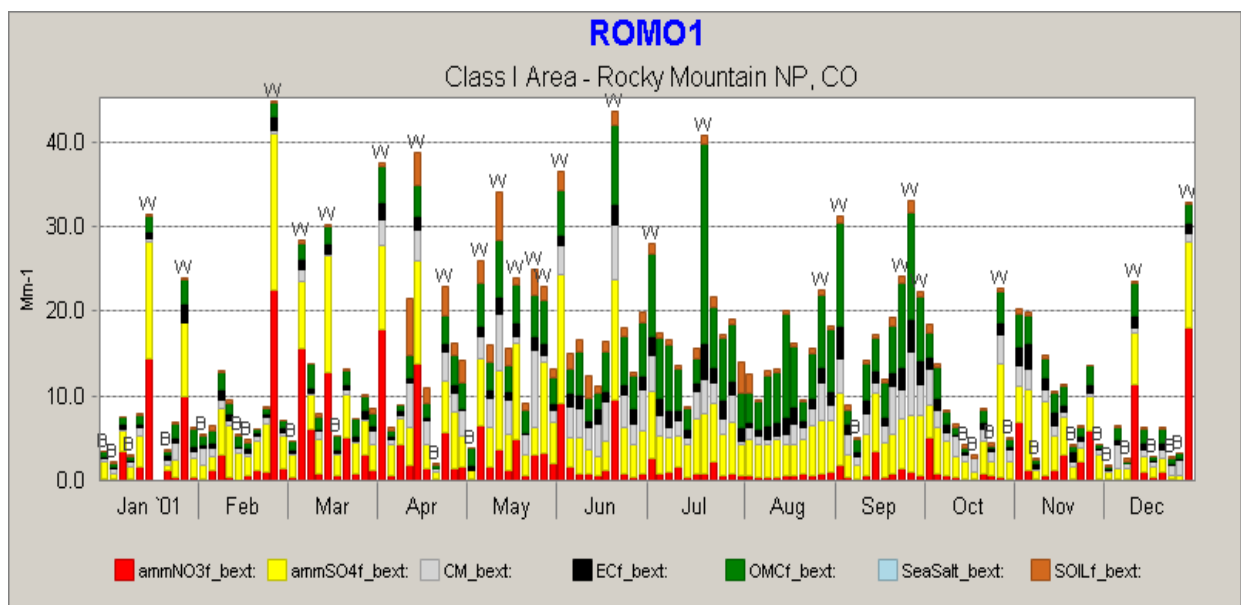


Figure 16: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2001

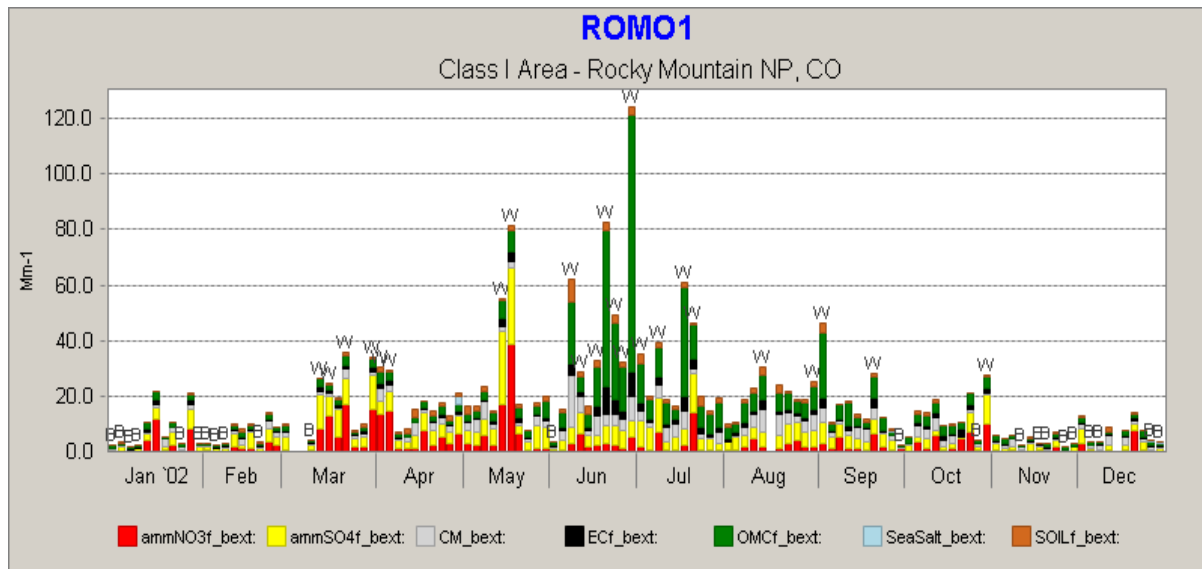


Figure 17: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2002

d. Overall Conclusions.

Colorado has among the best visibility in the country at its Class I areas and throughout other scenic and pristine parts of the State. However, on an episodic basis visibility can become impaired at all sites monitored.

Visibility on the best days is not degrading over time at any site in Colorado. This is good and important news as protecting the cleanest days is a critical aspect of the Class I visibility protection program.

Visibility on the worst days is a more complex assessment. Mesa Verde NP shows a slow and steady increase in impairment over time. Weminuche and Great Sand Dunes show a very slight increase in impairment. Rocky Mountain and Mt. Zirkel show little apparent trend. At all these sites the most recent years of complete data have large variation from year-to-year driven largely by the sustained drought in the West. In addition to direct impacts from the drought, fewer precipitation events equate to less of a potential for natural removal mechanisms (i.e., rain and snow storms) scrubbing particles out of the air. The data record for White River is too short to draw conclusions at this time regarding trends.

4. ADDITIONAL MEASURES, INCLUDING SIP REVISIONS, THAT MAY BE NECESSARY TO ENSURE REASONABLE PROGRESS TOWARD THE NATIONAL GOAL.

Substantive LTS SIP revisions occurred in August 1996, April 1997, and April 2001. The 2002 SIP revision was to update outdated language and create a better overall organization of the LTS portion of the SIP. A minor update occurred in 2004. The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However,

once again, small updates and edits are proposed in order that this part of the SIP does not become outdated.

5. THE PROGRESS ACHIEVED IN IMPLEMENTING BART AND MEETING OTHER SCHEDULES SET FORTH IN THE LONG-TERM STRATEGY.

Hayden. Emission limitations and schedules for Hayden Generating Station were adopted into the SIP on August 15, 1996 based on the Hayden Consent Decree. By terms of the Decree, Hayden Station must provide progress reports to the State concerning construction of new equipment and compliance with new emission limitations. The particulate and SO₂ control equipment for Units 1 & 2 have been installed and are operating. All schedules in both the Decree and in the SIP regarding Hayden were met, some up to six months ahead of deadlines in the SIP and Consent Decree. Both units were in compliance for all pollutants by November 16, 1999. The emission limits and reporting requirements have been integrated into Hayden's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2001. Since then Hayden has continued to operate the facility within its emission limits and has remained in compliance.

Craig. Emission limitations and schedules for Units 1 and 2 of the Craig Station were adopted into the SIP on April 19, 2001 based on the Craig Consent Decree. By the terms of the SIP, progress reports must be provided to the State.

Unit 1's tie-in with its new equipment began on September 13, 2003 and completion of PM, NO_x and SO₂ upgrades were finished by December 19, 2003. Testing of the NO_x upgrades continued through the end of 4th quarter 2003. SO₂ removal has consistently been above 90% since mid-December 2003 (limit is 90%). The NO_x limit is 0.30 lbs/Mmbtu annual average and the end of 2005 actual average was 0.279 lbs/Mmbtu.

Unit 2's tie-in began on March 13, 2004. The compliance period began on October 1, 2004 for all subject pollutants. SO₂ emissions from Unit 2 have also consistently achieved better than 90% removal and the NO_x annual average has been below the required 0.30 lbs/Mmbtu.

The emission limits and reporting requirements have been integrated into Craig's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2005. Since then Craig has continued to operate the facility within its emission limits and has remained in compliance.

6. THE IMPACT OF ANY EXEMPTION FROM BART.

The Division has not made a reasonable attribution decision. The need for a BART analysis has not been triggered, therefore, exemptions were neither requested nor granted.

7. THE NEED FOR BART TO REMEDY EXISTING IMPAIRMENT IN AN INTEGRAL VISTA DECLARED SINCE PLAN APPROVAL.

There have been no integral vistas listed by either the federal land managers or the State since the plan was approved. Therefore, a discussion on the need for BART in such integral vistas is not necessary.

IV. CONSULTATION WITH FEDERAL LAND MANAGERS

The Division is required by federal and state law to provide at least 60 days to consult with the federal land managers during periodic reviews of the LTS. The Division is sending this report to the USFS and NPS at the time of the request for hearing before the Air Quality Control Commission. These agencies are the managers of all of Colorado's Class I areas.

V. ENDNOTES AND REFERENCES

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1. Letter to Honorable Roy Romer, Governor of Colorado, from Elizabeth Estill, Regional Forester, U.S. Forest Service Rocky Mountain Region, July 14, 1993.
 2. "Revision of Colorado's State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements," adopted by the Colorado Air Quality Control Commission, April 19, 2001.
 3. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements," 66 Federal Register, 35374.
 4. Watson, J.G. and D. Blumenthal 1996, *Mt. Zirkel Wilderness Area, Reasonable Attribution Study of Visibility Impairment; Volume II: Results of Data Analysis and Modeling, Part 1 of 2 -- Final Report*; July 1, 1996. Desert Research Institute, University and Community College System of Nevada, 5625 Fox Avenue, Reno, Nevada 89506.
 5. In the United States District Court for the District of Colorado, Civil Action No. 93-B-1749, Sierra Club, Plaintiff, vs. Public Service Company of Colorado, Inc., Salt River Project Agricultural Improvement and Power District, and PacifiCorp, Defendants, United States of America and State of Colorado, Plaintiff-Intervenors, Consent Decree, date lodged in Court, May 22, 1996, date entered in Court, August 19, 1996.
 6. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements," January 16, 1997, 62 Federal Register, 2305.
 7. "Craig Station FGD System Modifications – Analyses of Potential Alternatives, Project Design Basis and Cost Estimates", EPA Contract #'s 68-D7-0001 – Phase # 1-005 & 9X-0264-NALX, dated August 31, 1999.
 8. C.R.S. 25-7 Part 10, "Air Quality Related Values – Class I Federal Areas."
 9. Letter to Honorable Bill Owens, Governor of Colorado from William P. Yellowtail,

Regional Administrator, EPA Region 8; September, 22, 1999.

10. Letter from Tom L. Thompson, Acting Regional Forester, U.S.D.A. Forest Service, Rocky Mountain Region to Margie Perkins, Director, Colorado Air Pollution Control Division, December 14, 2000.
11. “Regional Haze Regulations,” July 1, 1999, 64 Federal Register 35714, (codified at Part 40 Code of Federal Regulations sections 51.308 and 309).
12. “IMPROVE Data Guide: A Guide to Interpret Data”, University of California Davis, August 1995.

APPENDIX B

Regional Haze State Implementation Plan ***SIP Revision for RAVI Long Term Strategy***

LONG-TERM STRATEGY REVISION

OF

COLORADO'S STATE IMPLEMENTATION PLAN

FOR CLASS I AREA VISIBILITY PROTECTION

ADDRESSING REASONABLY ATTRIBUTABLE

IMPAIRMENT

January 2011

This document is the Phase I Long-Term Strategy (LTS) revision of the State Implementation Plan (SIP) of Colorado's Class I Visibility Protection Program addressing reasonably attributable visibility impairment (RAVI). The Phase I RAVI LTS review is a separate document and contains background information and the review/report sections as required by EPA and State law.

The state adopted this SIP revision in order to update the LTS. The state adopted an LTS SIP revision in 2007, which was submitted to EPA in 2008 as part of the Regional Haze SIP. For various reasons this submittal was not acted on by EPA. Because of substantial revisions to the Regional Haze SIP in 2010, the state updated, amended and re-adopted this RAVI LTS in 2010. This SIP revision is intended to amend the 2004 LTS portion of the Class I Visibility SIP.

References in this SIP revision to Colorado Air Quality Control Commission Regulation No. 9 (Open Burning, Prescribed Fire, and Permits) are intended only to provide information about the location of various aspects of Colorado's smoke management program. Regulation No. 9 is neither being submitted for EPA approval nor incorporated into the SIP by reference. It implements Colorado's program and is not federally required. The State is precluded from submitting this Regulation No. 9 for incorporation into this SIP by C.R.S. 25-7-105.1.

The State of Colorado believes the strategies, activities, and plans outlined below in sections for Existing Impairment, Prevention of Future Impairment, Smoke Management, and Consultation and Communication with Federal Land Managers constitute reasonable progress toward the national visibility goal under Phase I. The following Long-Term Strategy addresses the visibility issues that currently face the State of Colorado's Class I units within the framework of EPA's Phase I of the visibility protection program. The six factors required by the EPA to be considered in a LTS are embedded within the strategies below and marked with an asterisk for reference.

I. EXISTING IMPAIRMENT.

The LTS must have the capability of addressing current and future existing impairment situations as they face the State. Generally, Colorado considers that its Air Quality Control Commission, Regulation No. 3, Part B, §XIV.D (“Existing Impairment”) meets this long-term strategy requirement regarding existing major stationary facilities. The State believes that its existing regulations along with the strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal.

A. Existing Impairment and the Mt. Zirkel Wilderness.

1. The Certification.

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that it was reasonable to believe that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and that local existing stationary sources - the Craig and Hayden power stations - contributed to the problem.

2. Reasonable Progress for the Mt. Zirkel Wilderness.

a. Hayden.

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. An agreement, the Hayden Consent Decree, was approved by the federal district court on August 19, 1996. The agreement was between the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice. The Decree was intended to resolve a number of issues, including a Sierra Club lawsuit against the Hayden Station, the needs of the State’s visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC. The State believes that these significant emission reductions will effectively eliminate the visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has indicated that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.

The construction of Hayden’s control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and emission limitations for NO_x, SO₂, opacity, and particulate matter are being achieved. The relevant emission limitations and monitoring requirements have been moved into the facility’s Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

b. Craig Generating Station (Yampa Project).

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999.

After Hayden was resolved in August 1996, the State's attention turned to Craig Station Units 1 and 2. In addition to the State and the USFS visibility certification, there are other issues concerning the emissions from Yampa Valley power plants. The USFS has strong concerns about local emissions of SO₂ and NO_x that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. As well, a citizen lawsuit under the Clean Air Act by the Sierra Club directed against Craig Station Units 1 and 2 regarding opacity issues was initiated in late 1996.

After several years of preliminary efforts, studies and workshops, in Fall 1999 the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. The Craig owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. It was approved by the court on March 19, 2001. The State resolved the certification of impairment in relation to Units 1 and 2 of Craig Station by the AQCC adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The Forest Service concluded that all of its concerns related to the Craig Station and the 1993 Certification of Impairment are now resolved. Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NO_x, SO₂, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

3. BART and Emission Limitations.

Although BART determinations were not made by the State regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations* for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. These SIP amendments also address the enforceability of Hayden's and Craig's emission limitations* (the dates when the facilities must comply with emission limitations and the enforcement structure have been previously adopted into this LTS). Source retirement and replacement* and construction activities* are not required in the SIP or LTS at this time as the Division is unaware of any relevant issues triggering such a necessity. Note that BART determinations under the Regional haze regulations are described in Chapter 6 of the Regional Haze SIP.

a. Hayden's Emission Limitations.

The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 are incorporated into this LTS SIP by reference.¹ EPA approved this SIP amendment on January 16, 1997.²

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

b. Craig's Emission Limitations.

The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 are incorporated into this LTS SIP by reference. The SIP revision was adopted by the AQCC on April 19, 2001³ and EPA published final approval of the SIP amendment after a public comment period on July 5, 2001.⁴

4. Monitoring.

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area. The Division commits to coordinating a monitoring strategy with other agencies and providing periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. The Division worked collaboratively in 2005 with the U. S. Geological Survey to assess the effects of Hayden's emission reductions. The Division plans on conducting a more comprehensive evaluation of both Craig's and Hayden's effects combined. This work should be completed in 2011 after a suitable period of data has been collected.

B. Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance*.

There are no outstanding certifications of visibility impairment in Colorado. In addition, the Division has found no evidence that other stationary sources potentially subject to BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA or any other Class I area in Colorado under Phase I of EPA's visibility program. The USFS certification of visibility impairment at Mt. Zirkel Wilderness Area has been completely resolved. The Division recognizes that regional haze impacts all of Colorado's Class I areas, including MZWA. The State is prepared to respond to any future certifications as per AQCC Regulation No. 3 § XIV.D.

C. Ongoing Air Pollution Programs*.

1. PM₁₀.

The State of Colorado has attained and maintained the PM₁₀ standard in its non-attainment areas throughout the State. PM₁₀ attainment and maintenance plans have been approved by EPA for Aspen, Canon City, Denver, Lamar, Pagosa Springs, Steamboat Springs, and Telluride. These various plans contain numerous air pollution control programs that are effectively reducing emissions. The attainment and maintenance of the PM₁₀ standard will likely have some small effect (since the standard is only rarely exceeded) on improving visibility in pristine and scenic areas. The Division is committed to maintaining the PM₁₀ standard throughout the State.

2. Urban Haze -- Brown Cloud.

There is a concern about urban haze in the eastern Front Range urban corridor from the Denver metropolitan area to Fort Collins. This Front Range area is approximately 25-50 miles from Rocky Mountain National Park, a Class I area. The National Park Service, the federal land manager of the Park, has not certified visibility impairment in the Park. Analysis of urban Brown Cloud data in Denver indicates it has improved approximately 28% between 1991 and 2006. The Division will provide periodic trend analysis of the urban Brown Cloud as data

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

permits and continue to provide technical support to efforts to understand and reduce the Brown Cloud.

3. Emissions in the Four Corners Area.

The cumulative growth of many minor sources of air pollution, including mobile, area and stationary sources, can slowly lead to degradation of air quality and have visibility impacts. Federal land managers have commented in previous Phase I LTS review/revision cycles regarding concerns about the cumulative emissions and their possible impacts on Class I areas in the southwest portion of Colorado.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning. An executive/steering committee of the Four Corners Task Force that includes representatives from the states of Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables were developed to ensure that all options developed are timely and a final report was issued in November 2007. The report contains analyses of over 100 emission mitigation options that could be utilized in future discussions on reducing emissions in that region.

4. Plan for Rocky Mountain National Park.

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

The Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and Early Action Compact/SIP preparation for ozone.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative's progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a

new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP was approved by the AQCC in April 2007. This plan documented the science of nitrogen deposition and the ecological impacts, presented long-term deposition reduction goals, documented current and potential NO_x and ammonia emission reduction options, and established a path for future activities. The plan acknowledges that emission reductions measure targeted at reducing N deposition will likely benefit visibility at RMNP. Colorado intends on analyzing the visibility improvement benefit of any deposition-targeted measure.

One of the commitments made in the 2007 NDRP was to develop a contingency plan that would put in place corrective measures in the event that initial and any subsequent interim deposition goals are not realized. Such a plan was adopted by the Colorado Air Quality Control Commission in June 2010. This contingency plan does not automatically require the implementation of additional emission control measures designed to reduce the deposition of nitrogen in RMNP. Instead, a focused process to develop appropriate responses if and when nitrogen deposition goals are not achieved was adopted.

The Division maintains a website that is a clearinghouse for information related to the Initiative and contains the 2007 NDRP and the 2010 Contingency Plan. Please see:

<http://www.cdphe.state.co.us/ap/rmnp.html>

II. PREVENTION OF FUTURE IMPAIRMENT.

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal.

A. Ongoing Air Pollution Programs*.

1. PSD and NSR.

Generally, Colorado considers that its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities. The State believes that its existing regulations along with the efforts outlined below have together provided for reasonable progress toward the national visibility goal.

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

a. Modeling.

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division's expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division's web site at: <http://www.colorado.gov/airquality/permits.aspx> The Division will continue to update its modeling guidance as needed to insure estimated impacts are projected in as technically sound a manner as reasonably possible.

III. SMOKE MANAGEMENT PRACTICES*.

The LTS requires that smoke management practices of prescribed burning be addressed.

A. The Colorado Smoke Management Memorandum of Understanding and AQCC Regulation No 9.

Until 2002, Colorado's open burning regulation did not specifically address wildland prescribed fire. In this absence, operational understandings evolved over many years between the Division and the users of prescribed fire for grassland and forestland management. Until January 2002, these understandings regarding the details of permitting and reporting of prescribed fire activity were contained in the Colorado Smoke Management Plan and Memorandum of Understanding (MOU). The Colorado Department of Public Health and Environment, the Forest Service, National Park Service, Bureau of Land Management, Fish and Wildlife Service, Air Force Academy, U.S. Army (Fort Carson), U.S. D.O.E. Rocky Flats Field Office, City of Boulder Wildland Fire Department, Colorado Division of Wildlife, and the Colorado State Forest Service were voluntary signatories to the MOU. The AQCC adopted Regulation No. 9 (Open Burning, Prescribed Fire and Permitting) on January 17, 2002. Adopting this regulation includes the voluntary requirements contained in the MOU and applies them to all users of prescribed fire. In addition, the regulation implements Senate Bill 01-214. Overall, Regulation No. 9 is the main vehicle in Colorado for addressing smoke management from general open burning as well as prescribed wildland burning.

B. SB01-214 and Smoke Management Program Development.

Colorado Senate Bill 01-214 ("Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Thereof") became law in 2001. Regulations implementing it were adopted as part of Regulation No. 9. The statute and implementing regulations require significant users of prescribed fire for grassland and forestland management to conform to the State standard to "minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable in order to minimize the impact or reduce the potential for such impact on both the attainment and maintenance of national ambient air quality standards and achievement of federal and state visibility goals." All significant users are to submit planning documents to the Commission. The regulation asks that planning documents explain the

* A factor that must be considered in a LTS SIP revision according to EPA regulation.

decision process and criteria the significant user applies to making choices about fuel treatment alternatives to achieve various land management goals and must demonstrate how the significant user will comply with the State standard. Each planning document will have a public hearing before the AQCC. The AQCC is to review and make recommendations and comments for each planning document. Starting in July 2002, the Division cannot issue burning permits to any significant user of prescribed fire if their plan for an area is not consistent with Commission comments and recommendations. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, Trinchera Ranch, Denver Water Board, Blue Valley Ranch, and Larimer County.

The statute also requires fees. Regulation No. 9 specifies that significant users shall pay fees of \$59.98/hour to the Division for review of planning documents. Prescribed fire permittees also pay for the cost of the prescribed fire program based on a cost distribution methodology described in the regulation. The cost of the program is currently about \$199,000 annually.

It is the State's intention that through this processes described above, the plans and practices of significant users will continue to consider air quality and visibility concerns into their fuel management decision making.

The Division will also continue to annually produce a report on prescribed burning activity and estimated emissions. The report will contain estimates of acres burned, piles burned, and estimated resulting emissions. The Division has annually prepared such reports since 1990.

The regulation, encompassing the new permitting regulation and the implementation of SB01-214, embodies a comprehensive smoke management program with elements relating to review and approval of wildland fuel management planning documents, permitting of specific fires, reporting actual activity, and a fee program regarding open burning. During 2005, the Division certified its program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. Each prescribed fire project is reviewed by Division staff consistent with Regulation No. 9 in the course of establishing smoke permit conditions. Approximately 300-350 wildland fire permit applications are processed each year.

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

IV. FEDERAL LAND MANAGER CONSULTATION AND COMMUNICATION.

The plans, goals, and comments of the federal land managers are to be addressed during SIP and LTS revisions. Good communication with the federal land managers is important to implementing the LTS and making reasonable progress toward the national goal.

A. Consultation.

The federal land managers (FLMs) with Class I areas in Colorado will be given opportunities to comment and provide input during the LTS review and revision process. The Division will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review and to publish the FLM comments and state responses. In accordance with the Regional Haze regulation, the schedule for reviewing and updating this RAVI LTS has been changed from an every three-year period to an every five-year period. The state commits to consult with the FLMs as described above during each five-year review of the LTS.

B. Monitoring Plan.

C.R.S. 25-7-212(3)(a) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to “develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan.” The agencies have indicated that they have developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA’s Regional Haze Rule (40CFR51.308(d)(4)) indicates, “The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State... Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments network.” The federal agencies’ monitoring plan relies on this network and ensures that each Class I area in Colorado will have an on-site monitor or an off-site monitor that is representative of visibility in the Class I area. In the 2004 LTS revision, the Division provided letters from the federal land managers and approval letters from the Division. This information is repeated in the 2010 revision and is included here to conform to the requirements of state law to incorporate the monitoring plans in this manner into the SIP.

V. ENDNOTES AND REFERENCES

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1. “Long-Term Strategy Review and Revision of Colorado's State Implementation Plan For Class I Visibility Protection, Part I: Hayden Station Requirements, Section VI. C „Enforceable Parts of the SIP Revision: Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting“”, August 15, 1996, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted August 19, 1996 by the Colorado Air Quality Control Commission.
 2. “Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements,” January 16, 1997, 62 Federal Register, 2305.
 3. “Revision of Colorado’s State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements, Section III „Enforceable Portion of the SIP Revision, Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting“, March 13, 2001, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted April 19, 2001 by the Colorado Air Quality Control Commission.
 4. “Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements,” 66 Federal Register, 35374.

APPENDIX C

Regional Haze State Implementation Plan ***Technical Support for the BART Determinations***

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
CEMEX Inc. – Lyons Cement Plant**

I. Source Description

Owner/Operator: Cemex
Source Type: Portland Cement Manufacturing
Kiln Type: Modified Long-dry Kiln
Review: Best Available Retrofit Technology (BART)

History:

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two potential BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO₂ and NO_x emissions. The raw material dryer emits minor amounts of SO₂ and NO_x; in 2008 Cemex reported SO₂ and NO_x emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results.



Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex Lyons kiln. The

newer Portland cement plants studied by EPA, utilize multistage preheater/precalcliner designs that are not directly comparable. Cemex has a unique single stage preheater/precalcliner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalcliner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalcliner vessels where temperatures are ideal (between 1600-2000°F) for reducing NO_x to elemental Nitrogen.

Process Description:

Limestone and other raw materials extracted from the quarry are processed through a primary crusher at the Dowe Flats quarry. The crushed material is transported to the plant on a 2.0 mile belt conveyor system and discharged to a stockpile. The stockpiled material is placed on a belt by means of a front end loader to be processed through a primary crusher, the dryer, and a secondary crusher. The material from the secondary crusher is stored in raw material storage silos.

These storage silos contain silica and iron ore and various quarried raw materials. Material from these storage silos is discharged to weigh belts for the formulation of a desired product. The weigh belts discharge to the raw mill. The raw mill mixes and crushes the blended materials and delivers the homogenized material to storage silos. The homogenized material from the storage silos is delivered to the calciner portion of the kiln. Pulverized coal from the coal mill is fired at the bottom of the flash calciner. The partially calcined material from the calciner then enters the 14 foot 3 inch diameter - 245 foot long rotary kiln, which is located at a slight incline along its horizontal axis. The Cemex kiln process-type is best categorized as a modified long dry kiln. The material travels towards the clinker discharge end where additional pulverized coal is fired for the clinkering process. The clinker is discharged from the kiln into the clinker cooler where it is cooled by air forced through the clinker bed by under grate fans. The cooled clinker is then moved to internal storage in an A-Frame building, or outside storage stockpiles. The stored clinker is the raw material for the finish mill. In the finish mill the clinker is combined with gypsum and other additives, ground to a fine material and stored in product silos. The material in the product silos can be loaded for bulk transport, or sent to a packaging system.

From an overall perspective, the manufacturing process may be viewed as two segments -- clinker production and cement production. The clinker storage allows the two processes to operate at different production rates. During periods of low demand for cement, clinker is accumulated. If cement is in high demand, the clinker production can be supplemented by purchase of clinker from other sources. The overall result is the clinker production can operate at a rather steady rate, while the cement production can operate in response to the current or projected demands.

II. Source Emissions

There are two BART eligible units at the Cemex facility, the dryer (point 003) and the kiln (point 007). Regulation Number 3 requires sources to submit an Air Pollution Emission Notice (APEN) on each emission point at least every five years. Typically, emission points with low emissions are updated every five years whereas points with higher emissions are updated annually, since fees are assessed on these emissions.

Table 1 lists the APEN reported emissions from the dryer and emission inventory records collected during routine inspections. The 1999 APEN is based on emission factors, whereas the 2003, 2008 and 2009 APENs are based on a stack test. The Division has determined that the 2008 emissions best represents baseline emissions for the dryer since stack test data is considered more reliable than emission factors. Furthermore, the 2008 clinker production is representative of typical operations because it falls within the normal range of the historical average (please see Table 3 below). Consequently, for purposes of this analysis the dryer has baseline emissions of NO_x = 10.41 tpy; SO₂ = 0.89 tpy; and PM₁₀ = 5.12 tpy; based on a recent stack test.

Table 1: Dryer Emissions

Dryer SCC - 30500620				
Pollutant	SO ₂	NO _x	PM ₁₀	CO
Allowable Emissions* [tpy]	36.70	13.90	22.80	57.30
1999 APEN Emissions [tpy]	31.10	13.30	22.20	55.40
2003 APEN Emissions [tpy]	0.64	1.83	1.89	3.83
2008 APEN Emissions [tpy]	0.89	10.41	5.12	2.97
2009 APEN Emissions [tpy]	0.37	4.27	2.10	1.22
Baseline [tpy]	0.89	10.41	5.12	2.97
% Baseline is below Allowable Emissions	-97.8%	-25.1%	-77.5%	-94.8%
Baseline Emissions [lbs/ton of Clinker]	0.004	0.04	0.02	0.01

* Current emission limitations are contained in operating permit (95OPBO082)

Table 2 below lists the emissions from the kiln. The APEN reported SO₂, NO_x and CO emissions are based on continuous emission monitoring systems (CEMS) and the PM₁₀ emissions are based on periodic stack tests. The Division has determined that the 2002 emissions best represent baseline emissions for the kiln because it corresponds to the high range for SO₂ emissions (which can vary significantly due to pyrites in the limestone) and NO_x emissions are within the normal historical range along with clinker production which is near the historical average. There is an increase in kiln PM₁₀ emissions starting in 2007 because of a change in CDPHE's APEN reporting policy, which allows for the grouping of common stacks associated with kiln (process group P007) and a change to reporting PM₁₀ emissions based on periodic stack tests rather than the use of emission factors. Consequently, the 2002 PM₁₀ emissions are not the most realistic depiction of anticipated baghouse controls and actual emissions that are listed in more recent kiln (P007) APEN reports.

The EPA BART guidelines suggest that *"the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."* See [70 FR 39167]. There is some variation in the short-term and long-term SO₂ emissions depending on the raw material mix, type of clinker produced, and fuel used. Thus, historically there was some flexibility provided in developing the original permit limits to allow of the use of alternative fuels and raw materials, as well as longer averaging periods. The 10-year period (2000-2009) may represent a different kiln operation condition when compared to earlier periods because no petroleum coke was burned in

the kiln despite being permitted to burn such fuel. The Division determined that looking back at kiln operations prior to the year 2000 were not reasonable for purposes of BART. Consequently, the selection of 2002 as the kiln emissions baseline essentially precludes the use of petroleum coke since the use of such fuel would result in SO₂ emissions far above 95 tons per year.

The justification for selecting the highest SO₂ emission rate over a baseline period is associated with the fact that cement kiln SO₂ emissions are not as predictable as a coal-fired boiler (power plant). The sulfur in the coal is sole source of SO₂ at a power plant, whereas a cement kiln has two sources, the coal fuel and the sulfide impurities (iron pyrite) in the limestone and other raw materials added to the kiln. Consequently, it is much easier, although still a challenge, to maintain compliance with SO₂ limits at coal-fired power plants through careful blending of various coals, or purchasing compliant coal to achieve more consistent sulfur content. Conversely, coal blending for cement kilns only addresses one source of SO₂, the other source (the raw materials) varies depending on impurities in the mining deposit and other additives used in clinker production.

Table 2: Kiln Emissions

Kiln SCC – 30500606 (120 tons/hour maximum feed rate – 967,680 tons/year dry basis)				
Pollutant	SO ₂	NO _x	PM ₁₀	CO
Allowable Emissions [tpy]	1,340.0	2,649.0	133.0	396.0
2000 APEN Emissions [tpy]	14.4	1,729.6		
2001 APEN Emissions [tpy]	18.7	1,858.9	8.7	233.2
2002 APEN Emissions [tpy]	95.0	1,747.1	8.5	235.3
2003 APEN Emissions [tpy]	48.0	1,835.0	9.6	210.0
2004 APEN Emissions [tpy]	26.3	1,708.9	9.1	209.0
2005 APEN Emissions [tpy]	27.2	1,591.3	8.5	156.0
2006 APEN Emissions [tpy]	44.7	2,011.7	8.5	239.2
2007 APEN Emissions [tpy]	65.0	1,689.0	56.0	311.0
2008 APEN Emissions [tpy]	55.8	1,295.5	42.0	345.1
2009 APEN Emissions [tpy]	15.5	495.5	17.5	102.4
Baseline [tpy]	95.0	1,747.1	8.5	235.3
% Baseline is below Allowable Emissions	-92.9%	-34.0%	-93.6%	-40.6%
Baseline Emissions [lbs/ton of Clinker]	0.402	7.388	0.036	0.995

The average clinker production over the period (2000 – 2008) is 486,031 tons. The year 2009 was excluded from the average as clinker production was well below the average production level.

Table 3: Kiln-Flash Calciner – Historical Emissions

Year	Actual Clinker Production [tpy]	SO ₂ [tpy]	SO ₂ [lbs/ton of Clinker]	NO _x [tpy]	NO _x [lbs/ton of Clinker]
2000	539,992	14.4	0.053	1,729.6	6.42
2001	508,733	18.7	0.074	1,858.9	7.31
2002	472,945	95.0	0.402	1,747.1	7.39
2003	516,251	48.0	0.186	1,835.0	7.11
2004	472,053	26.3	0.111	1,708.9	7.24
2005	440,384	27.2	0.123	1,591.3	7.23
2006	466,173	44.7	0.192	2,011.7	8.63
2007	479,225	65.0	0.271	1,689.0	7.05
2008	478,520	55.8	0.233	1,295.5	5.41
2009	185,076	15.5	0.167	495.5	5.35

III. BART Evaluation

There are two BART eligible units at the Cemex facility, the dryer and the kiln. The dryer is natural gas-fired with actual emissions of NO_x = 10.41 tpy; SO₂ = 0.89 tpy; and PM₁₀ = 5.12 tpy; based on a recent stack test. CALPUFF modeling¹, of the dryer and kiln combined indicates a 98th percentile visibility impact (at Rocky Mountain National Park) of 0.78 delta deciview² (Δdv) and 98th percentile visibility impact at of only the kiln is 0.76 Δdv ³. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv . Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the Division has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the Division has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any measurable visibility improvement which is a fundamental factor in the BART evaluation. Consequently, the current SO₂, NO_x and PM₁₀ emission limits (see Table 1 –Dryer Allowable Emissions) established in the Cemex – Lyons Operating Permit (95OPBO082) have been determined to satisfy the requirements for BART.

III.A. Review of Sulfur Dioxide Controls on the Kiln

Step 1: Identify All Available Technologies

Cemex originally identified four available technologies for the removal of sulfur dioxide from Portland cement kilns. A copy of Cemex's BART analysis is included with this analysis as an attachment, and provides further support and documentation for the conclusions reached herein. The Division added Dry Sorbent Injection (DSI) as another option that is available for control of

¹ Cemex Inc., Lyons Colorado - BART Five Factor Analysis; dated August 29, 2008

² Table 3-6 of the Cemex BART Five Factor Analysis

³ Table 4-7 of the Cemex BART Five Factor Analysis

SO₂ emissions. The Division also reviewed the RACT/BACT/LAER clearinghouse and other BART analyses develop the following list of available technologies:

1. Fuel Substitution
2. Raw Material Substitution
3. Lime Addition to Kiln Feed
4. Dry Sorbent Injection
5. Wet Lime Scrubbing

Step 2: Eliminate Technically Infeasible Options

Cemex concluded that fuel substitution and raw material substitution are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that each of the foregoing technologies is “technically feasible” for the facility, as that term is discussed in EPA’s BART guidelines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

1. Fuel Substitution:

Cemex is authorized to burn coal, coke and tire derived fuel (TDF) at the facility, although coal is the primary fuel. The coal used in the kiln typically has a sulfur content of less than 1.5%, whereas the sulfur content of coke can be as high as 6% sulfur. Removal of SO₂ is inherent to the cement manufacturing process as the hot combustion gases come in contact with the limestone generating free lime, which then reacts with the SO₂ in the free gas stream resulting in removal of sulfur in the clinker product. Removal efficiencies in rotary kiln systems can range between 38% and 99% of sulfur input. Cemex estimates the SO₂ removal efficiency of about 80%. Based on the low level of SO₂ emissions (based on CEMS) emitted from the kiln, it is apparent that a high level of SO₂ control is achieved through the inherent removal process within the kiln. Since inherent removal accounts for at least 80% reduction in kiln SO₂ emissions, any further lowering of the sulfur content of the fuel results in about a 20% reduction in directly emitted SO₂.

In November 2002, a preliminary performance (stack) test was conducted on the kiln that compared fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 40% reduction in SO_x in the exhaust stream. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable emission control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement.

Cost of Compliance:

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about \$172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above annual cost and the estimated 40% SO₂ reduction, the control cost is estimated at about \$4,531 per ton of SO₂ reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

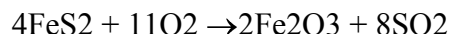
The source uses low sulfur coal and inherent removal of SO₂ emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

No impact

2. Raw Material Substitution:

Sulfide sulfur in the raw materials (primarily limestone), usually in the form of iron pyrite, is thermally decomposed and oxidized or “roasted” to form SO₂. The pyritic sulfur reacts with oxygen according to the following reaction:



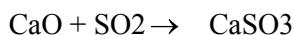
Using raw materials with lower pyritic sulfur content would reduce the potential for SO₂ emissions from the kiln system. However, while pyrites are present in the limestone and other raw materials used at the plant, concentrations of sulfide sulfur in these materials is typically low. On average, the sulfide content of the raw materials is less than 2%. It is uncertain that lower sulfur content materials are available. Since the raw materials and fuel used at the plant already have very low sulfide sulfur, raw material substitution is not likely to produce significant sulfur reductions.

Similar to most cement plants, the Cemex facility is built near the mine source of limestone, the primary raw material for cement manufacture. To require transport of materials with lower sulfide concentrations from elsewhere would impose an economic penalty that would cause most plants to be economically infeasible. During the production of cement clinker, the limestone loses about one-third of its weight as CO₂. The shipping costs for the “lost” weight in the limestone can be economically prohibitive.

The Division has determined that raw material substitution with a different source of limestone is not a practical control option as SO₂ emissions vary depending on the level of pyrite contamination which is inherently difficult to predict. Consequently, raw material substitution has been eliminated from further review and consideration.

3. Lime Addition to Kiln Feed:

Lime Addition to Kiln Feed at the Lyons plant would consist of mixing lime (CaO) with the raw Kiln feed. The CaO would react with SO₂ driven off in the kiln to form calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄) according to the following reactions:





These reactions can occur in the calciner, throughout the rotary kiln, and in the lower stages of the flash calciner (i.e., at any location in the system at which CaO and SO₂ are present simultaneously and are mixed adequately). The amount of SO₂ absorbed through this mechanism at any location in the pyroprocess is dependent on the site-specific temperature and other factors such as the time of contact between the reactants. Once sulfur is absorbed as CaSO₄ in the materials in the pyroprocess, it is unlikely to be released again as SO₂. CaSO₄ would be retained in the raw mix and ultimately be converted into clinker. Cemex anticipates that Lime Addition to Kiln Feed could achieve 25% control of the SO₂ emitted from the system. Considering the length of the kiln and the corresponding amount of contact time, it appears that 25% control of SO₂ is possible depending on the amount of lime that is fed into the kiln.

Cost of Compliance:

The cost of Lime Addition to Kiln Feed was determined by calculating the cost of the CaO needed to react with the SO₂ in the system. In an exhaust gas stream, the molar ratio of CaO needed to react with a mole of SO₂ (to achieve a near 90% reaction) is on the order of 1:1. However in the situation of Cemex – Lyons, adding the CaO directly to the feed would result in a diminished effectiveness because of the lower SO₂ concentrations. Cemex has indicated that, based on data from Cemex's Wampum, PA plant, an addition of 2-3 ton/hr of CaO to a similar Kiln feed stream resulted in approximately a 25% reduction in the SO₂ concentration (from 600 ppm down to 450 ppm). The concentration of SO₂ in the gas stream at the Lyons plant is significantly lower (a typical 24-hr average is in the 6 ppm range) and it is unknown how much more CaO is needed to achieve the desired reduction. Since the typical emission range at Cemex-Lyons is 100 times lower than the tested levels at Cemex-Wampum, it is expected that more CaO would be needed to achieve adequate contact time with the lower concentrations of sulfur in the exhaust stream. Moreover, the effectiveness of CaO addition is further limited by the alkali byproducts associated with the use of more CaO. Consequently, Cemex has conservatively estimated that it could take about 4 tons per hour of CaO addition to achieve a 25% SO₂ reduction.

Cemex – Lyons kiln is limited to 8,064 hours per year of operation based on a permit limit in the Operating Permit (95OPBO082), thus the resulting annual CaO usage is 32,256 tons (4*8064). Cemex's 2007 BART application identified the CaO cost at \$60/ton, but this was for raw CaO (un-calcined) which has different properties. The appropriate material is the use of calcined CaO (lime or quick lime) which cost about \$143/ton. Therefore, the annual operating cost would be 32,256 tons x \$143/ton = \$4,612,608. The lime (CaO) addition would yield approximately 90% conversion to clinker, or 29,030 tpy of clinker, which has a value of \$1,161,216 @ \$40/ton. Therefore, the actual operating cost would be approximately \$4,612,608 - \$1,161,216 = \$3,451,392. At 25 % control effectiveness, the annual SO₂ emissions would be lowered from the proposed permit limit of 95.0 tpy to 71.25 tons/year. The cost effectiveness would be approximately \$153,271 per ton of SO₂ removed.

Energy Impacts and Non Air-Quality Impacts:

Alkali impurities in the CaO could result in additional wasting of kiln dust to meet low alkali limits. Additional fugitive PM₁₀ emission may result from handling of the CaO.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO₂ emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for lime addition to kiln feed.

4. Dry Sorbent Injection:

Dry Sorbent Injection (DSI) utilizes finely ground sorbent which is injected in the gas stream of the kiln. The sorbent typically used is a hydrated lime, sodium bicarbonate or Trona (soda ash). Water may be injected separately from the sorbent either downstream or upstream of the dry sorbent injection point to humidify the flue gas. The relative position of the dry sorbent and water injection is optimized to maximally promote droplet scavenging or impacts between sorbent particles and water droplets, both suspended in gas stream. Fly ash, reaction products, and any unreacted sorbent are collected in the particulate control device.

Cost of Compliance:

Cemex did not provide any DSI costs specific to the Lyons kiln.

Energy Impacts and Non Air-Quality Impacts:

There are no energy or non-air quality impacts associated with dry sorbent injection.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO₂ emissions through contact with the clinker which results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for dry sorbent injection.

5. Wet Lime Scrubbing:

Wet lime scrubbing (WLS) is the term used for a traditional tailpipe wet scrubber. This process involves passing the flue gas from the main PMCD through a sprayed aqueous suspension of Ca(OH)₂ or CaCO₃ (limestone) that is contained in an appropriate scrubbing device. In WLS the SO₂ reacts with the scrubbing reagent to form CaSO₃ that is collected and retained as aqueous sludge. Typically, the sludge is dewatered and disposed in an on-site landfill. In some cases involving cement plants, the CaSO₃ sludge could be oxidized to CaSO₄ and used in the finish mills as a substitute for purchased gypsum for regulation of the setting time of the cement product. Typically, WLS is considered to have a scrubbing efficiency of up to 90 percent of the SO₂ in the flue gas treated by the scrubber. *See Cemex BART submittal at 4-4, citing "EPA Fact Sheet – Flue Gas Desulfurization (FGD) Wet, Spray Dry, and Dry Scrubbers."*

Cost of Compliance:

Cemex performed an economic analysis to determine the annualized cost for WLS based on a recent vendor bid for a cement plant with a similar exhaust flow rate. The "annual tons reduced" were determined by subtracting the estimated controlled annual emissions from the Division proposed annual permit limit of 95 tpy SO₂. The estimated controlled annual emissions, 9.5 tpy,

were calculated by applying 90 percent control efficiency to the 95 tpy of SO₂. Utilizing this methodology and correcting a math error on the amount of sludge generated, the estimated annualized cost⁴ is \$2,529,018 for WLS, the projected SO₂ control cost per ton is \$29,579/ton. A detailed cost analysis is included in Table 4-5 of Cemex's BART submittal, which was corrected by the Division to account for the longer amortization period.

Energy and Non Air-Quality Impacts: Wet Lime Scrubbing (WLS)

Based upon its experience, the Division has determined that wet scrubbing has several negative energy and non air quality environmental impacts, including significant water usage which is a precious commodity in the arid West. Cemex estimates that an appropriately sized wet scrubber would consume approximately 16 million gallons of water per year. Most of this water would be emitted as a steam vapor with a small portion in the sludge that would be generated by the control device. A wet scrubber would also require an additional fan of considerable horsepower to move the flue gas through the scrubber.

Wet scrubbing may also lead to an increase in PM emissions at the Cemex facility, because some particles of limestone or CaSO₄ will be entrained in the flue gas and subsequently be emitted from the scrubber. Wet scrubbing is also known to increase emissions of sulfuric acid mist.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO₂ emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln is impacted by the remaining life of the quarry, which Cemex has estimated to be approximately 8 years from the date that a BART control would be required based on the expiration of Boulder County SUP 93-14 for quarry operations. The continued viability of the cement production operation relies on finding additional limestone feedstock of very similar composition within a distance that allows for economic operation. The Division is not aware that Cemex has successfully secured additional limestone supplies that would provide additional useful life to the facility. Presently, Cemex is unwilling to consent to closure date in the operating permit therefore the Division has used 20 years as the capital recovery period.

⁴ Capital Recovery based on an assumed 20 year life and 7% interest rate

Table 4 below lists the most feasible and effective options, ranked by control effectiveness.

Table 4: Kiln SO₂ Control Options

Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO ₂ Emissions [lbs/hr]	Annual Controlled SO ₂ Emissions [tpy]	Annual Controlled SO ₂ Emissions [lb/ton of Clinker]
Baseline SO ₂ Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	19.0	71.3	0.30
Fuel Substitution (coal supplemented with TDF)	40%	15.2	57.0	0.24
Dry Sorbent Injection	50%	12.7	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

Table 5 below lists the SO₂ emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 5: Summary of Cost Effectiveness of SO₂ Control Technologies for the Kiln

Control Technology	SO ₂ Emission Reduction [tons/yr]	Annualized Cost [\$ /yr]	Cost Effectiveness [\$ /ton]	Incremental Cost Effectiveness [\$ /ton]
Baseline SO ₂ Emissions	-			
Lime Addition to Kiln Feed	23.8	\$3,640,178	\$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	\$172,179	\$4,531	-\$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	\$2,529,018	\$29,579	\$49,618

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control scenarios. Cemex also conducted refined CALMET modeling which indicates that Rocky Mountain National Park is the only Class I Area where the Lyons plant causes or contributes to visibility impairment. Cemex's refined modeling is discussed in detail in the attached Cemex BART 5-Factor Analysis which was reviewed by the Division and found to meet all required performance requirements.

The amount of visibility improvement associated with various SO₂ control scenarios using CALPUFF modeling are listed in Table 6.

Table 6: Visibility improvement for SO₂ Controls – Kiln Only

Control Method	98th Percentile Impact (Δv)	98th Percentile Improvement (from 24-hr Max) (Δv)	Cost Effectiveness (\$/ Δv)
24-hr Maximum (≈ 104 lbs/hr)	0.760	-	
Baseline (≈ 25.3 lbs/hr)*	0.730	0.030	
Lime Addition to Kiln (≈ 19.0 lbs/hr)*	0.727	0.033	\$110,308,420
Fuel Substitution (≈ 15.2 lbs/hr)*	0.726	0.034	\$5,064,088
Dry Sorbent Injection (≈ 12.7 lbs/hr)*	0.724	0.036	
Wet Lime Scrubbing (≈ 2.5 lbs/hr)	0.720	0.040	\$63,225,462

* - Visibility impacts interpolated from original BART modeling

The SO₂ baseline of 95 tons/year is based on 2002 APEN report which results in a 0.03 Δv of visibility improvement over the 24-hour maximum emission rate of 104 lb/hour (419 tons/year). The SO₂ reduction from lime addition to kiln feed is estimated at 25% and the anticipated degree of visibility improvement (from 24-hr Maximum) is about 0.033 Δv at a cost of \$110.3 million dollars per Δv . The control efficiency of fuel substitution could be as high as 40% (about 38 tons/year) based on very limited testing and the anticipated degree of visibility improvement (from 24-hr Maximum) is about 0.034 Δv at a cost of \$5 million dollars per Δv . Dry sorbent injection has a visibility improvement of 0.036 Δv , based on an estimated 47.5 tpy reduction in SO₂ emissions. Wet lime scrubbing reduces SO₂ emissions by about 85.5 tpy with 0.04 Δv visibility improvement at a cost of \$63 million dollars per Δv . The visibility projections for the below listed emission levels are based on scaling the existing BART modeling.

Step 6: Select BART Control

The Division reviewed the Cemex data on raw material substitution. Since the raw materials (mostly limestone) consumed at the plant typically have low sulfide sulfur content, material substitution would not result in a significant reduction in SO₂ in the Kiln. The Division agrees that raw material substitution is not an appropriate or realistic SO₂ control technology for the Kiln.

The Division has eliminated the Lime Addition to Kiln Feed SO₂ control option from consideration based on excessive cost (\$153,271 per ton) and minimal visibility improvement (0.033 Δv). Despite not having cost information on Dry Sorbent Injection, the Division has determined that the minimal visibility improvement of 0.036 Δv does not justify further consideration of this control technology.

The Division has eliminated the Wet Lime Scrubbing SO₂ control option from consideration based on excessive cost (\$29,579 per ton) and minimal visibility improvement (0.04 Δv improvement). Moreover, wet scrubbing has a number of adverse energy and environmental impacts as described above.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that process control (inherent removal in the kiln) from the 2002 baseline period represents Best Available Retrofit Technology for control of SO₂ emissions in the kiln. Table 7 specifies the Division SO₂ BART determination of 25.3 pounds per hour and 95.0 tons

per year that are 12-month rolling averages. The Division considered establishing an SO₂ emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the SO₂ BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 7: SO₂ Emission Limits on the Kiln

Subject Unit	SO ₂ Control Technology	SO ₂ Emission Limits
Kiln System	Inherent Removal	25.3 lbs/hr (12-month rolling average)
		95.0 tons/yr (12-month rolling average)

The federal BART rule requires that emission limits must be enforceable and specify a reasonable averaging time consistent with established reference methods. The Division finds that in consideration of the potential for variability in SO₂ emissions associated with pyrites in the limestone and other raw materials used at the plant, an annual averaging period provides long-term compliance with the low levels of SO₂ emitted from the kiln while allowing for short-term variability in SO₂ emissions. Shorter term averaging periods are not practical as the sources of the sulfur impurities are not readily detectable in the quarry materials. The type of cement produced also potentially impacts the variability of SO₂ emissions in the kiln feed mix which necessitates longer averaging periods.

In consideration of establishing the SO₂ emission limit, the Division reviewed not only the 5 factor analysis, but also looked at emission limits from the RACT/BACT/LAER clearinghouse to determine SO₂ emission limits for other cement kilns across the nation. The Division was unable to find an operationally similar kiln to the Cemex - Lyons kiln, but the SO₂ emission limits for newer higher efficiency kilns do establish a reasonable range to consider. Table 8 identifies SO₂ limits ranging from 0.2 to 12.0 lb per ton of clinker. In comparing the Division proposed SO₂ BART limit (approximately equal to 0.40 lb per ton of clinker) to the values approved for new Portland cement kilns in the RACT/BACT/LAER clearinghouse, it is well below the higher limits established in Missouri, and is slightly higher than those established in Florida.

Table 8: RACT/BACT/LAER data for Cement Kilns

RBLC ID	SO ₂ Control	SO ₂ Limit	Units	Year
FL 0297	Process	0.2	lb/ton clinker	2007
MO-0072	Process	1.93	lb/ton clinker	2006
FL-0271	Process	0.2	lb/ton clinker	2006
FL-0268	Process	0.23	lb/ton clinker	2004
FL-0267	Process	0.28	lb/ton clinker	2004
SD-003	Process	632	ton/hr	2003
MO-0059	Wet Scrubber	12	lb/ton clinker	2002
IA-0052	Process	4850	ton/year	2002
TX-0355	Process	20	lb/hr	2001
FL-0139	Process	0.27	lb/ton clinker	2000

The Division also evaluated a recent local BACT determination (2007) on Grupo Cementos de Chihuahua (GCC) Rio Grande Pueblo Portland cement plant that establishes a SO₂ emission limit of 1.99 lb/ton of clinker. In considering the RBL clearinghouse ranges and a recent Colorado BACT determination, the Division finds that the proposed SO₂ BART limits (approximately equal to 0.40 lb/ton of clinker) to be a reasonable limit for such a relatively small SO₂ emission source.

Accordingly, based upon its consideration and weighing of the five factors, the Division has determined that the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual SO₂ emission limits of 25.3 lbs/hour and 95.0 tpy (approximately equal to 0.40 lb per ton of clinker) as SO₂ BART for the kiln at this facility. No additional controls are warranted because about 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO₂ control. Additional SO₂ scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

III.B. Review of Nitrogen Oxide Controls on the Kiln

As explained above, in Section III, no evaluation of the dryer is warranted because of extremely low emissions. Based on actual 2008 data, the NO_x emissions from the kiln are 1295.5 tpy and the raw material dryer are 10.41 tpy. Since the average emissions from the dryer (about 2.8 pounds per hour) are very small compared to the kiln (about 343.9 pounds per hour); the following BART evaluation focuses only on the kiln.

Step 1: Identify All Available Technologies

The primary pollutant of concern for regional haze from the Lyons plant is the NO_x generated from the kiln system. Cemex's current allowable NO_x emission rate is 2,649 tpy NO_x, which equates to an average allowable emission rate of 667 pounds NO_x per hour based on the permit limit of 8064 hours of operation per year. Using 2002 as the baseline, the annual average NO_x emission rate is 464.3 lbs/hr (1,747.1 tpy) or about 4.73 lbs/ton of dry kiln feed.

Variations in kiln NO_x emissions occur with the composition of the raw materials used to produce different types of cement, which depends on market demand. Also, changes in the raw materials (natural rock composition) and seasonal temperature variations occur, as indicated in the following excerpt from a study⁵, *"The results of these changes range from zero emissions of NO_x during a complete outage of the system to significantly higher than normal NO_x emissions when the fuel input is increased to restore the process equilibrium and a normal production rate. More subtle changes in the process, e.g. variations in ambient temperature (short-term and seasonal), variations in the feed rates or fuel or raw materials, demand operator responses that also serve to vary NO_x emissions. For a variety of factors, the operation of some pre-calciner kiln systems is more stable than others. Almost invariability, however, pre-calciner kiln systems exhibit more stable operation than the three other types of kiln systems, and experience the least variability in NO_x emissions."* The Cemex - Lyons kiln is a modified long dry kiln, thus some consideration of a longer averaging period is appropriate to account for variation in NO_x emissions depending on cement product produced and variations in raw materials.

⁵ See "Variability of NO_x Emissions from Precalciner Cement Kiln Systems", Walter L. Greer, Curtis D. Lesslie

Cemex identified six available technologies for the removal of NO_x from Portland cement kilns. The Division reviewed the RACT/BACT/LAER Clearinghouse and other BART analyses and agrees with CEMEX's identification of available technologies. The available technologies are the following:

1. Water Injection
2. CKD Insufflation
3. Firing Tire-Derived Fuel
4. Indirect Firing with Low NO_x Burners (LNB)
5. Selective Non Catalytic Reduction (SNCR)
6. LNB with SNCR
7. Selective Catalytic Reduction (SCR)

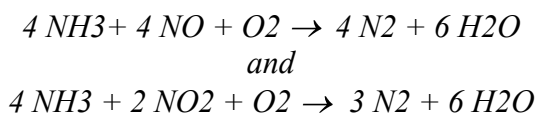
Step 2: Eliminate Technically Infeasible Options

Cemex has concluded that water injection and kiln dust insufflation are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that these technologies are "technically feasible" for the facility, as that term is discussed in EPA's BART guidelines. As further discussed below, however, the Division has also determined that water injection and kiln dust insufflation are not appropriate NO_x controls for purposes of BART at the facility.

7. Selective Catalytic Reduction (SCR):

Selective catalytic reduction (SCR) refers to the reduction of NO_x in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term "selective" refers to the unique ability of ammonia to react selectively with NO_x. The EPA released a NO_x control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns," EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce NO_x emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith form) and promotes the NO_x reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C]), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:



The first equation is the predominant reaction because 90-95% of NO_x in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a NH₃: NO_x molar ratio of 1.05–1.1:1 to achieve a NO_x conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The NO_x removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to NO_x, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired NO_x reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:

After the PM control device – a “low-dust” system

After the last cyclone without ducting – a “high-dust” system.

The advantages of a “low-dust” system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 mg/m³ (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm³ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m³. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.

The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.

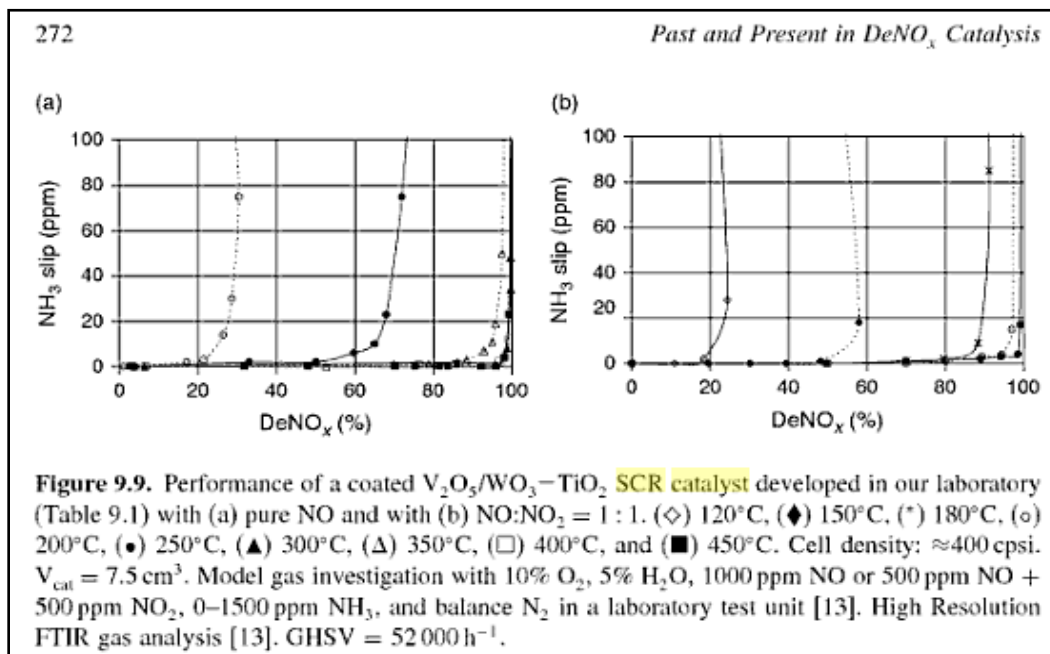
The design of a SCR system is expected to be site specific. According to Schreiber⁶, the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 1, from Granger⁷ shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NO_x reduction

⁶ See Schreiber, R, *et al* “Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry”, (2006)

⁷ See Granger, P. Elsevier, “Past and Present in DeNO_x Catalysis: From Molecular Modeling to Chemical Engineering”, (2007)

efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350°C to 450°C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NO_x reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

Figure 1: Catalyst Performance for NO_x Control and Ammonia slip at Various Temperatures



Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. Each challenge presents additional confounding issues related to the application at the Cemex – Lyons facility due to the unique design of the modified long dry kiln. A good catalyst must ensure high activity and selectivity for NO_x reduction and low activity in the oxidation of SO₂ to SO₄. Because of the high selectivity, the catalyst will have a specific temperature window at which the NO_x reduction is optimal (Granger 2007). Specific to the Cemex – Lyons kiln, the exit temperature, after the baghouse, will require reheating of the exhaust gases to reach the optimal temperature for effective NO_x control. If post NO_x control cooling is required, additional water usage would be necessary along with the challenges of the resultant high moisture (20-25%) exhaust gas stream.

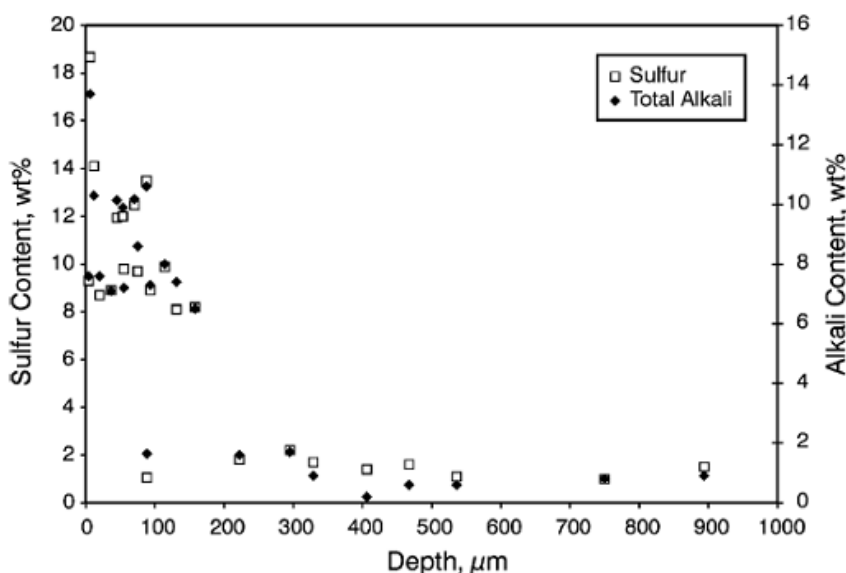
There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NO_x reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson⁸, alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.*, 2008, and Strege *et al.*, 2008). Figure 2 shows evidence of catalyst poisoning by both sulfur and alkalies⁹.

⁸ See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)

⁹ See Strege, J. *et al.*, "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NO_x control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NO_x reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst. The exit gas of the Cemex – Lyons kiln presents additional specific issues including moisture in the exhaust stream and alkali dust. The combination of both could result in rapid loss of catalyst activity depending on the type of catalyst materials used.

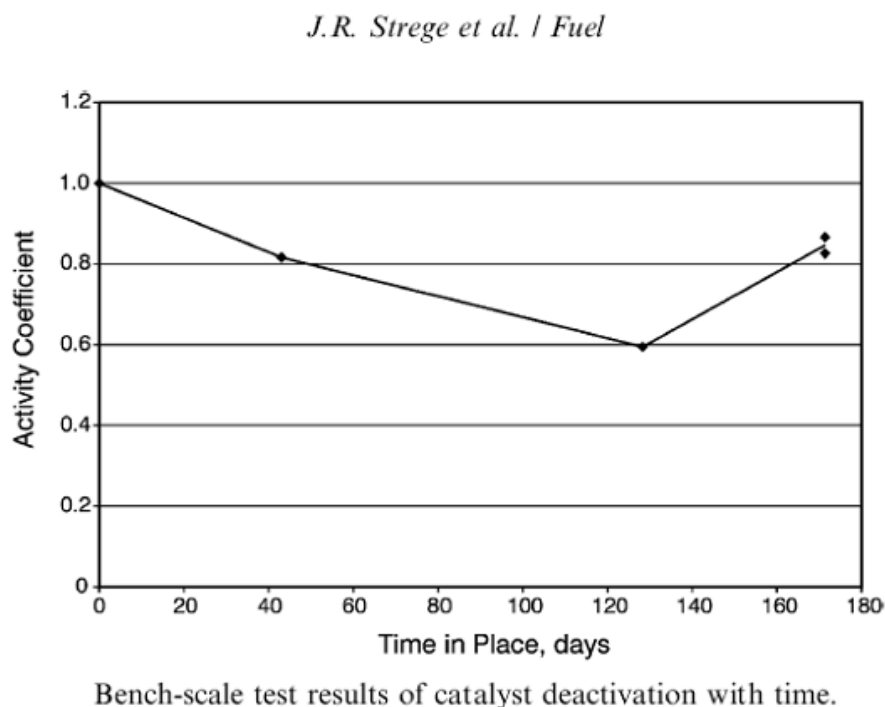
Figure 2: Sulfur and Alkali Penetration into the pores of the catalyst



Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

The above figure indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NO_x reduction (see Strege *et al.*, 2008).

Figure 3: Bench Scale Test Results of Catalyst Deactivation over a Period of Time



The above figure provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NO_x conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro¹⁰, a good flow distribution is needed to ensure minimal ammonia slip. The Cemex – Lyons kiln has neither the temperature nor the flow characteristics necessary for optimal catalyst performance. Another concern for the Cemex – Lyons kiln, is the potential for ammonia slip to create visibility impairment that is readily transported into nearby Rocky Mountain National Park.

Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time.

Of the four major vendors contacted, two, Lurgi PSI Inc. (Lurgi) and Babcock & Wilcox, did not provide any proposal, with Lurgi stating that their technology was not yet ready for commercial release. A third with relevant experience from the Solnhofen demonstration plant, KWH, indicated that technical uncertainties prevented them from designing an SCR system. Only Alstom provided a proposal that suggested SCR could be supplied to a cement kiln system.

¹⁰ See Barbaro, P.; Bianchini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

However, careful review of the Alstom proposal indicated that the Alstom proposal did not identify a commercial SCR system that would be viable for a cement kiln system application.

The Division finds that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe that differ significantly from the Cemex – Lyons kiln design does not constitute “available” control technology for purposes of BART. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *“The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst.”* Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse as would be required for the Cemex - Lyons kiln, which is a modified long-dry kiln design. The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be “available” for purposes of retrofitting such control technology on an existing source. BART should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, the Division has eliminated SCR as an available control technology for purposes of BART.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

1. Water Injection:

The injection of water or steam into the main flame of a kiln can act as a heat sink to reduce the flame temperature. Since NO_x formation is a function of the flame temperature and residence time at that temperature, water injection reduces the generation of thermal NO_x. Cemex - Lyons has stated that its own experience indicates that water injection can reduce the thermal NO_x by approximately 7%. The Division anticipates some reduction in thermal NO_x formation when water is injected into the area where the flame temperature is the highest. Aside from actual testing in the kiln, a 7% reduction seems reasonable.

Cost of Compliance:

Based on information from Cemex – Lyons, the Division estimates the annualized costs of water injection at about \$43,598 with minimal annual operating costs. Assuming a 7% NO_x reduction, the control cost is about \$356 per ton of NO_x reduced.

Energy Impacts and Non Air-Quality Impacts:

The only non-air quality impacts associated with water injection is the use of a precious resource in limited supply in the arid west.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for water injection.

2. Cement Kiln Dust Insufflation:

Cement Kiln Dust (CKD) is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. CKD is most often treated as a waste even though there are some beneficial uses. However, as a means of recycling usable CKD to the cement pyroprocess, CKD sometimes is injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame has the effect of cooling the flame and/or the burning zone thereby reducing the formation of thermal NO_x. The insufflation process is somewhat counterintuitive because a basic requirement of a cement kiln is a very hot flame to heat the clinkering raw materials to about 2700°F in as short a time as possible. Because of the thermal inefficiency associated with the practice, CKD insufflation is not an attractive control option for NO_x. While the Division does not agree that the thermal inefficiency makes kiln dust insufflation technically infeasible, the Division has determined that that inefficiency, coupled with the much greater reduction achieved through SNCR (discussed below), render insufflation inappropriate for the Cemex plant. Cemex provided additional information that indicates that CKD insufflation is not typically done because of operational issues including ring formation in the kiln. Consequently, the Division is not evaluating this control option further because of operational issues and the greater reduction achieved through SNCR.

3. Firing Tire-Derived Fuel:

Secondary combustion is defined as follows: a portion of the fuel is fired in a location other than the burning zone. This reduces thermal NO_x generation because the temperature in the secondary combustion zone is less than 2100 °F. Firing of solid fuels, such as used tires, is an example of secondary combustion. The Cemex – Lyons kiln has conducted testing of tire derived fuel (TDF) which can be introduced at the kiln feed shelf, creating a secondary combustion zone in the riser between the kiln and the combustion chamber.

In November 2002, a preliminary performance (stack) test was conducted to compare fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 24.4 % reduction in NO_x in the exhaust stream. Cemex estimates that firing TDF can reduce NO_x by 10% on a long term basis if utilized. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable NO_x reduction control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement. Potentially, TDF could be used in combination with other control technologies, such as SNCR to meet additional BART NO_x reduction objectives.

Cost of Compliance:

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about \$172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above

annual cost and the estimated 10% NO_x reduction, the control cost is estimated at about \$986 per ton of NO_x reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact

4. Indirect Firing with Low-NO_x Burners:

Low NO_x burners (LNBs) reduce the amount of NO_x formed at the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). As applied to the rotary cement Kiln, the low-NO_x burner creates primary and secondary combustion zones at the end of the main burner pipe to reduce the amount of NO_x initially formed at the flame. In the high-temperature primary zone, combustion is initiated in a fuel-rich environment in the presence of a less than stoichiometric oxygen concentration. The oxygen-deficient condition at the primary combustion site minimizes thermal and fuel NO_x formation and produces free radicals that chemically reduce some of the NO_x that is being generated in the flame.

In the secondary zone, combustion is completed in an oxygen-rich environment. The temperature in the secondary combustion zone is much lower than in the first; therefore, lower NO_x formation is achieved as combustion is completed. CO that has been generated in the primary combustion zone as an artifact of the sub-stoichiometric combustion is fully oxidized in the secondary combustion zone.

The EPA has indicated that a 14% reduction in NO_x emissions may be anticipated in switching from a direct-fired standard burner to an indirect-fired LNB. This is based on a study conducted on an indirect-fired LNB at the Dragon Product Company cement kiln at the plant located in Thomaston, Maine. However, the EPA has also determined that the emission reduction contribution of the LNB itself and of the firing system conversion direct to indirect cannot be isolated from the limited data available. The terms direct and indirect firing have unique meaning in the context of Kiln firing (unlike the more general meanings where direct firing implies that the products of combustion contact the process materials whereas indirect firing involves a heat transfer medium). In Kiln firing, direct and indirect firing describes the manner in which pulverized fuel is conveyed from the fuel grinding mill to the burner. Cemex has estimated that a LNB would lower NO_x by 20% at the Lyons plant.

Cost of Compliance:

Cemex also provided information from a NESCAUM report (Dec 2000) that indicates 20-30% NO_x reduction can be achieved through the use of indirect firing with LNBs. Cost data was included from a study of California Portland Cement (Colton, CA) that evaluated TDF along with indirect firing w/LNBs that indicates \$7 million capital cost and \$350,000 annual O&M costs. This study includes TDF firing and does not separate out the actual cost associated with

the indirect firing with LNBs. The Division has estimated the annualized cost at about \$710,750 with a result control cost of about \$2,034 per ton of NO_x reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

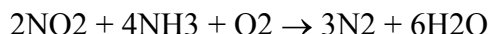
None.

Remaining Useful Life:

No impact

5. Selective Non-Catalytic Reduction (SNCR):

In the relatively narrow temperature window of 1600 to 1995°F, ammonia (NH₃) reacts with NO_x without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions.



As applied to NO_x control from cement kilns and other combustion sources, this technology is called Selective Non-Catalytic Reduction (SNCR). Above this temperature range, the NH₃ is oxidized to NO_x, thereby increasing NO_x emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH₃ may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH₃ could be delivered to the kiln system through the use of anhydrous NH₃, or an aqueous solution of NH₃ (ammonium hydroxide) or urea [(NH₂)₂CO]. A concern about application of SNCR technology is the breakthrough of unreacted NH₃ as “ammonia slip” and its subsequent reaction in the atmosphere with SO₂, sulfur trioxide (SO₃), hydrogen chloride (HCl) and/or chlorine (Cl₂) to form a detached plume of PM₁₀ –PM_{2.5}.

SNCR is being evaluated at 45 to 50% control efficiency depending on the averaging period. The Cemex kiln/flash calciner configuration is best described as a modified long dry kiln. The Division has conducted extensive research and has not found any documentation on similar kiln types. EPA’s Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns (November 2007) addresses only new cement kilns. These new kilns are multi-stage (4 or 5 stage) preheater/precalciner kilns and are not comparable to Cemex – Lyons unusual modified long dry kiln. The Division has also considered the Cemex Brooksville plant in Florida, but it is a multi stage preheater design and is not comparable to the Lyons facility. The Division’s evaluation reveals that the Solnhofen facility achieved only 50% reduction with SCR. Significantly, the Division is concerned that requiring a higher reduction through SNCR (beyond 45% on a 30 day rolling average) could cause excessive ammonia slip that would exacerbate the nitrogen deposition concerns at Rocky Mountain National Park. Considering the close proximity of Cemex to RMNP, any unreacted ammonia (slip) is available to react with oxides of nitrogen or sulfur to form particulates (nitrate or sulfate) a potentially significant contributor to visibility impairment.

It is important to note, that all kilns are not created equal. Modern 5-stage preheater/calciner kilns are not an appropriate comparison to the unusual and modified configuration of the Cemex

– Lyons 40-year old kiln. Consequently, it is difficult to assert what amount of NO_x reduction can be achieved with SNCR controls on this older modified long dry kiln. It is important to realize that a higher SNCR control efficiency in a long type kiln necessitates the injection of more ammonia (higher molar ratio) to increase the opportunity for reacting with oxides of nitrogen. This is particularly important to understand with older kilns where operating parameters are often less than the engineering ideal. Often residence time and temperature limit the effectiveness of the reaction. Any excess ammonia (slip) that fails to react, largely because the temperature is too low, is exhausted out the stack to eventually form particulates which counteracts the original basis for the emissions control –visibility. Thus, if EPA desires higher control efficiency, the penalty is more visibility impairment downwind of the source. Therefore, the engineering evaluation must consider the balance between high control efficiency and ammonia slip.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about \$1,636,636 per year. Assuming a 48.43% NO_x reduction, the control cost is about \$1,934 per ton of NO_x reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

6. Selective Non-Catalytic Reduction with Low NO_x Burners (LNB):

Cemex conducted a BART analysis for the kiln located in Lyons, Colorado and concluded that SNCR could reduce nitrogen oxides (NO_x) emissions on a long-term basis by about 50 percent. Various entities have suggested that Cemex provide an analysis combining low NO_x burners and SNCR with the goal of achieving a higher NO_x reduction, perhaps as high as 60 percent. Accordingly, this analysis has been revised to evaluate the combination of low NO_x burners and SNCR.

In the cement manufacturing industry, it is well known that thermal NO_x represents the majority of the NO_x formation in cement kiln systems. Thermal NO_x is a side effect of the high temperatures necessary in the cement kiln to produce a quality clinker product. One effort to combat the thermal NO_x formation in the cement industry has been the installation and use of LNB. LNB have been used to a limited degree in the cement industry for over 30 years. The concept of LNB is to minimize primary air as a source of nitrogen, reduce flame turbulence, delay air and fuel mixing, and establish a fuel rich zone for initial combustion. The resulting longer, less intense flame from the staging of combustion in this manner reduces flame temperatures and is therefore thought to reduce thermal NO_x formation.

In practice, LNB create two distinct combustion zones: the primary and the secondary combustion zones. In the primary, or initial, combustion zone flame turbulence and air and fuel mixing are suppressed by decreasing the amount of primary air supplied to the burning zone. It

is well understood that the higher the primary air, the higher the NO_x from the kiln system.¹¹ Typical primary air for LNB ranges from 5 to 7 percent.¹² The result is a fuel-rich, oxygen-lean, high temperature combustion zone created by reducing the amount of primary air and delaying the combustion of all of the fuel. The peak flame temperatures in the primary combustion zone must be maintained high to initiate the clinkering reactions. However, thermal NO_x formation is thought to be suppressed due to the oxygen-lean environment in the primary combustion zone which generates excess CO and other radicals known to react with NO_x.

The primary combustion zone is followed by an oxygen-rich secondary combustion zone where fuel combustion is completed. Lower temperature secondary combustion air is mixed into the secondary combustion zone, thereby lowering the peak combustion temperatures. Although excess oxygen is available, NO_x formation is suppressed in the secondary combustion zone because the temperatures are insufficient for significant thermal NO_x formation.

The Lyons Plant is currently equipped with a two channel, straight pipe burner with one channel for coal and a second channel for air used to adjust the momentum of the flame. The burner configuration is closer to a mono-channel than to a multi-channel burner definition. The measured primary air at the Lyons Plant ranges from 40 to 65 percent accordingly to the amount of momentum air used, with most of the primary air coming from the coal mill's minimum air evacuation requirements. The application of LNB at the Lyons Plant would primarily consist of replacing the existing main kiln burner.

The level of NO_x reduction reported in the literature for LNB applications on cement kiln systems vary considerably. Factors affecting the variability include, but are not limited to the specific type of LNB, pre-installation NO_x emission levels, kiln type, and fuels used. According to EPA's "Alternative Control Techniques Document Update – NO_x Emissions from Cement Manufacturing," EPA-453/R-94-004, March 2004, the NO_x reduction achievable with LNB ranges from 20 to 30% for typical kiln systems. The level of control achieved is generally greater for newer kiln systems. Many older kiln systems may achieve lower NO_x reductions due to the specific operating characteristics of the kiln systems. There are also a few non-typical kiln systems in the US, with one being the Lyons Plant. Considering the unique design and age of the Lyons Plant cement kiln system, it is uncertain whether meaningful NO_x reductions would be expected from the installation of LNB in combination with SNCR.

Cemex has proposed the installation and use of SNCR to achieve about a 50% NO_x reduction (long term) at the Lyons Plant. This level of NO_x reduction has been demonstrated on several cement kiln systems in the US, is recognized in the recently EPA proposed New Source Performance Standards as the demonstrable control efficiency for SNCR, and represents a high level of control with little risk of the known side effects to ammonia injection. The main risk for SNCR is the formation of a detached plume attributable to excessive ammonia slip due to injecting at too high of a normalized stoichiometric ratio (NSR) (i.e., pushing the SNCR technology too far to achieve higher levels of NO_x reduction leads to the formation of a detached ammonia plume, called ammonia slip). Ammonia slip from SNCR is non-existent to minimal when the reagent is injected at or below an NSR of about 0.7. Operating SNCR above this NSR significantly increases the ammonia slip to the point where conditions are favorable for the

¹¹ Battye, R., Walsh, S., and Greco, J. 2000. NO_x control technologies for the cement industry. Final report. Pages 30-31. EPA contract No. 68-D98-026.

¹² Battye, R., Walsh, S., and Greco, J. 2000. NO_x control technologies for the cement industry. Final report. Page 59. EPA contract No. 68-D98-026.

formation of a detached plume containing ammonium chloride and ammonium sulfide compounds. These compounds, as well as any unreacted ammonia, would result in visibility degradation which is counter to the intent of BART.

Therefore, the Division concludes that given the reasonable uncertainty in the benefits of LNB, the existing proposal to utilize the existing burner along with SNCR remains the best control option for the Lyons Plant kiln.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about \$1,686,395 per year. Cemex provided an estimated 55% NOx reduction resulting in an estimated control cost of about \$1,755 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

Table 10 below contains a ranking by control effectiveness of the remaining control technologies.

Table 10: Kiln NOx Control Options

Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NOx Emissions [lbs/hr]	Annual Controlled NOx Emissions [tpy]	Annual Controlled NOx Emissions [lb/ton of Clinker]
Baseline NOx Emissions	-	464.3	1,747.1	7.39
Water Injection	7%	431.8	1,624.8	6.87
Firing TDF	10%	417.8	1,572.3	6.65
Indirect Firing with LNB	20%	371.4	1,397.6	5.91
SNCR	45%	255.3	960.9	4.06
SNCR	48.43%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33
SCR	Not technically feasible			

Table 11 below lists the NOx emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 11: Summary of Cost Effectiveness of NO_x Control Technologies for the Kiln

Control Technology	NO _x Emission Reduction [tons/yr]	Annualized Cost [\$/yr]	Cost Effectiveness [\$/ton]	Incremental Cost Effectiveness [\$/ton]
Baseline NO _x Emissions	-			
Water Injection	122.3	\$43,598	\$356	
Firing TDF	174.7	\$172,179	\$986	\$2,453
Indirect Firing with LNB	349.4	\$710,750	\$2,034	\$3,083
SNCR (45% control)	786.2	\$1,636,636	\$2,082	\$2,120
SNCR (48.43% control)	846.1	\$1,636,636	\$1,934	\$1,864
SNCR w/LNB (55% control w/uncertainty)	960.9	\$1,686,395	\$1,755	\$434

Based on the above discussion, the combination of SNCR with LNB has an uncertain level of control due to the unique nature of the Lyons kiln. The Division has determined that SNCR is the best available NO_x control option for the Cemex – Lyons modified long dry kiln. Because Cemex has proposed SNCR as the preferred control option, it is not necessary or appropriate to further evaluate the lesser control options, including relative costs.

SNCR requires injection of the reagents in the kiln at a temperature between 870 to 1,090°C (1,600 to 2,000°F). In principle, any of a number of nitrogen compounds may be used as SNCR reagents (e.g., cyanuric acid, pyridine, and ammonium acetate). However, for reasons of cost, safety, simplicity, and by-product formation, ammonia and urea have been used in most of the SNCR applications. The selection of reagents is process and temperature specific. At higher temperatures, urea decomposes to produce ammonia, which is responsible for NO_x reduction. In cement kiln applications, ammonia typically has performed best as the reducing reagent. Because no catalyst is used to increase the reaction rate, the temperature window is critical for conducting this reaction. At higher temperatures, the rate of a competing reaction for the direct oxidation of ammonia, which actually forms additional NO_x, becomes significant. At lower temperatures, the rates of NO_x reduction reactions become too slow resulting in too much unreacted ammonia being released to the atmosphere (i.e., ammonia slip). The effective temperature window range can be lowered to about 700°C (1,300°F) by the addition of hydrogen along with the reducing agent.

The NO_x reduction efficiency of SNCR depends upon the temperature, oxygen, carbon monoxide, and residence time, as well as the ammonia and NO_x concentrations in the flue gas. Injection of ammonia at a NH₃:3 NO_x proportion of 1 to 1.5 will reduce NO_x emissions between 60 to 80 percent. Using a molar ratio of 0.5 will give NO_x reductions of approximately 40 percent. Work done by the German equipment supplier Polysius has shown that the optimum temperature for reduction of NO_x by ammonia is about 950°C (1,740°F), while for urea, the temperature increases to about 1,000°C (1,830°F).

Operating experience has identified several concerns with both ammonia and urea-based SNCR processes. The most frequently reported is the buildup of ammonium bisulfite or bisulfate scale, which is significant for sulfur-containing fuels. SNCR processes also appear to convert some NO_x to N₂O. The rate of N₂O formation is a weak function of both the reactant and the NO

concentration. However, N₂O formation seems to be inherently more prevalent in systems using urea than those using ammonia.

The NO_x destruction efficiency also depends upon the flue gas residence time in the appropriate temperature window. Unlike an SCR system where the reaction temperature is controlled in a dedicated reactor, an SNCR system relies on the existing gas temperature profile to provide an adequate residence time for a desired NO_x destruction. Maximum achievable NO_x reduction in a cement kiln may thus depend upon the gas temperature profile.

Based on the foregoing discussion and the potential for ammonia slip, the Division concludes that an assumed 45% NO_x reduction (30-day rolling average) and 48.43% NO_x reduction (annual average) from 2002 baseline is reasonable.

Step 5: Evaluate Visibility Results

An impact analysis was conducted to assess potential visibility improvements associated with SNCR. CALPUFF modeling was used as part of this analysis. The visibility improvement associated with various scenarios was calculated as the difference between the existing visibility impairment and the visibility impairment for the controlled emission rates as measured by the 98th percentile modeled visibility impact. Based upon the modeling, the addition of SNCR is projected to result in a 0.41 dv improvement.

Table 12: Visibility improvement for NO_x Controls – Kiln Only

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)	Cost Effectiveness (\$/Δdv)
24-hr Maximum (≈ 656.9 lbs/hr))	0.760		
Revised Baseline (≈ 464.3 lbs/hr)*	0.572	0.188	
Original Baseline (≈ 446.8 lbs/hr)*	0.555	0.205	
Water Injection (≈ 431.8 lbs/hr)*	0.540	0.220	\$198,174
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234	\$735,807
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279	\$2,547,493
Original BART Limit – SNCR (≈ 268.0 lbs/hr)	0.380	0.380	
Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)**	0.368	0.392	\$4,175,091
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408	\$4,011,363
SNCR w/LNB (≈208.9 lbs/hr) **	0.322	0.438	\$3,850,217

* - Visibility impacts interpolated from original BART CALPUFF modeling

** - Visibility impacts extrapolated from original BART CALPUFF modeling

Step 6: Select BART Control

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for

an effective NO_x control system. As discussed above, the combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NO_x emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NO_x control system available for this kiln.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that SNCR represents Best Available Retrofit Technology for control of NO_x emissions from the kiln. Table 13 specifies the Division NO_x BART determination of 255.3 pounds per hour (30-day rolling average) and 901.0 tons per year (12-month rolling average). The Division considered establishing a NO_x emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the NO_x BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 13: NO_x Emission Limits on the Kiln

Subject Unit	NO _x Control Technology	NO _x Emission Limits
Kiln System	Selective Non-Catalytic Reduction (SNCR)	255.3 lbs/hour (30-day rolling average)
		901.0 tons/year (12-month rolling average)

The Division has reviewed the analysis provided by Cemex and agrees that SNCR is the appropriate NO_x control technology. In reviewing the proposed emission rate of 255.3 lbs/hour (approximately equal to 4.06 lb/ton of clinker), the Division also looked at the RACT/BACT/LAER clearing house (see Table 14 below). The NO_x rate of 4.06 lb/ton clinker is consistent with determinations made in Iowa and Missouri, but is about double the proposed limits for the newer Florida kilns. The Cemex – Lyons facility is an older modified long dry kiln and does not have the precalciner systems developed for newer facilities specifically to reduce the temperatures for clinker formation. The use of lower temperatures also reduces the formation of thermal NO_x.

Table 14: RACT/BACT/LAER data for NO_x emissions from Portland Cement Kilns

RBLC ID	NO _x Control	NO _x Limit	Units	Year
FL 0297	SNCR	1.5	lb/ton clinker	2007
FL-0271	SNCR	1.95	lb/ton clinker	2006
FL-0268	SNCR	1.95	lb/ton clinker	2004
FL-0267	SNCR	1.95	lb/ton clinker	2004
SD-003	Preheater/calcliner	2267	tons/yr	2003
MO-0059	SNCR	8	lb/ton clinker	2002
IA-0052	Process	4	lb/ton clinker	2002
TX-0355	Process	660	lb/hr	2001
FL-0139	Process	2.9	lb/ton clinker	2000

The Division also reviewed the *U.S. v. Lafarge* Consent Decree, dated January 21, 2010. In that recent action, the NO_x reduction requirements established under the kiln retrofit options require

SNCR with a 12-month rolling emission limit of 4.89 lbs NO_x/ton of clinker. The BART Regulations do not require the demolition and reconstruction of any facility that is subject-to-BART. The proposed Cemex BART limit compares favorably to similar units addressed by the *Lafarge* Consent Decree and the RACT/BACT/LAER clearinghouse. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Because the Cemex kiln is a modified long dry kiln and is not directly comparable to the reported limits listed in the RACT/BACT/LAER clearinghouse, the Division finds that requiring an emission rate that falls into the range for modern sources that are more thermodynamically efficient (produce less NO_x) helps to further validate the stringency of the NO_x emissions rate selection.

The Division is aware that Cemex may be able to do better than a 45% reduction, and will require that 48.43% reduction on an annual basis (901.0 tons per year, 12-month rolling average). This limit results in reductions that are 68% lower than the current allowable NO_x limit (2,649 tpy) contained in the operating permit.

The Division also notes that the flash vessel at Cemex - Lyons is unique and may affect how well SNCR will perform at the plant. Because of this uncertainty the Division will not specify the ammonia injection or slip rate but will allow Cemex - Lyons to meet the NO_x limits through SNCR technology and process controls. Improving process controls may allow Cemex - Lyons to limit formation of NO_x in the kiln and thus meet the NO_x limits while reducing ammonia use. By requiring a 48.43% reduction on an annual basis, the Cemex BART determination almost matches the reductions achieved for both SCR and SNCR at the Solnhofen facility.

Accordingly, based upon its analysis and consideration of the five factors, the Division has determined that the higher NO_x emission rate is reasonable for the older cement kiln process, and that SNCR control at 255.3 lb/hr NO_x on a 30-day rolling average (which is about 4.06 lbs of NO_x per ton of clinker) is NO_x BART for the Cemex – Lyons facility. This BART determination will remove 45% of the NO_x emissions averaged over 30 days, and is projected to result in about 0.39 Δ dv in visibility improvement.

III.C. Review of Particulate Matter Controls on the Kiln and Dryer

PM emissions from the kiln are currently controlled by fabric filter baghouse and wet dust suppression techniques. Emission testing from the kiln has demonstrated compliance with the National Emission Standards for Hazardous Air Pollutants for Source Categories; Portland Cement Manufacturing Industry, 40 CFR Part 63 Subpart LLL. The NESHAP standard applies to the kiln and establishes PM emissions limits.

During development of the NESHAP standard, EPA was not able to identify any technologies for existing or new kilns that would consistently achieve lower emissions than the New Source Performance Standards (NSPS). Consequently, the level of the NESHAP standard is the same as NSPS and requires compliance with certain particulate emission limits and opacity limits. The NESHAP standard also includes emission limits for HCl and other hazardous pollutants; however these are not considered for their impact on visibility. The provisions of the NESHAP standard are already contained in the operating permit issued to Cemex – Lyons. For sources already regulated by a NESHAP standard, EPA stated the following in the BART guidelines:

“We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the

MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART.” [70 FR 39163]

The Division has reviewed the requirements of the NESHAP (MACT) for Portland cement production and evaluated the RACT/BACT/LAER clearinghouse database for other available particulate control options (see Table 15). The Division has determined that no new particulate control methodologies are identified that would improve upon the PM controls required in the NESHAP.

Table 15: RACT/BACT/LAER data for PM emissions from Portland Cement Kilns

FL 0297	Fabric Filter	0.1	lb/ton clinker	2007
MO-0072	Baghouse	0.516	lb/ton clinker	2006
FL-0271	Baghouse	0.1	lb/ton clinker	2006
FL-0268	Baghouse	0.2	lb/ton clinker	2004
FL-0267	ESP	0.2	lb/ton clinker	2004
SD-003	Fabric Filter	0.13	lb/ton	2003
MO-0059	Fabric Filter	99%		2002
IA-0052	Baghouse	0.5160	lb/ton clinker	2002
TX-0355	ESP	40	lb/hr	2001
FL-0139	Baghouse	0.11	lb/ton clinker	2000

Therefore, the Division is establishing the following PM and opacity limits as BART for particulate matter control that is based on the NESHAP 40 CFR Part 63 Subpart LLL:

Table 16: Particulate Matter Emission Limits on the Kiln and Dryer

Kiln System	Fabric Filter Baghouse	0.30 lb/ton of dry feed 20% opacity	0.275 lb/ton of dry feed 20% opacity
Dryer	Fabric Filter Baghouse	10% opacity	22.8 tons/year* 10% opacity

* Current emission limitation from Operating Permit (95OPBO082)

The Division has established a PM limit on the kiln system that is more stringent than the NESHAP, which is already in the Cemex – Lyons Operating Permit. Because the current NESHAP limits constitute the most stringent level of control, the State does not need to provide a five-factor analysis for PM for these units.

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Colorado Energy Nations, Golden, Colorado**

I. Source Description

Owner/Operator: Colorado Energy Nations Company (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek to the south and US Highway 58 borders the northern side of the CENC site. The large building to the north of CENC and south of Highway 58 is the Coors Brewery.



Figure 1: CENC facility Aerial Perspective

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operated in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM₁₀ by separate

fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in “NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado” Submittal provided on November 16, 2009 as well as additional information upon the Division’s request on February 8, 2010 and May 7, 2010. These documents are all provided as “CENC BART Submittals”. Table 1 depicts technical information for each BART-subject boiler at the CENC facility.

Table 1: CENC Facility BART-eligible Emission Controls and Reduction (%)

	Unit B004	Unit B005
Placed in Service	1975	1979
Boiler Rating, MMBtu/Hr for coal	360	650
Electrical Power Rating, Gross Megawatts	35	65
Description	Combustion Engineering Model CE-VU40 360 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP	Combustion Engineering Model CE-VU40 650 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP
Air Pollution Control Equipment	Wheelabrator-Frye Model 264 fabric filter baghouse with 8 compartments	Carter Day fabric filter baghouse with 12 modules
Monitoring Equipment	COM CEMs for SO ₂ , NO _x , CO ₂ , and stack gas	COM CEMs for SO ₂ , NO _x , CO ₂ , and stack gas

Emissions Reduction (%)	NO _x – None SO ₂ – None PM/PM ₁₀ – 99+%	NO _x – None SO ₂ – None PM/PM ₁₀ – 99+%

II. Source Emissions

CENC estimated that a realistic depiction of anticipated annual emissions for Boilers 4 and 5, or “Baseline Emissions”, to be conservative, was the maximum historical (2000 – 2005) 12-month (rolling) emissions experienced in the July 31, 2006 analysis. CENC also provided 2-year annual average emissions for comparison purposes.

Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The baseline emissions are used as the basis for estimating annual emission reductions for the various control technologies evaluated and determining the annualized costs to achieve those reductions. . The Division verified these emissions using Colorado’s Air Pollutant Emission Notices and EPA’s CAMD database as applicable. These emissions are summarized in Table 2.

Table 2: CENC Boilers 4 and 5 Baseline Emissions

Pollutant	Boiler 4		Boiler 5	
	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)
NO _x	600	0.50	691	0.34
SO ₂	781	0.64	1,406	0.71
PM ₁₀	11	0.003***	18	0.01***

*Using most recent three calendar years (CEMs data).

**The Division calculated 30-day rolling average rate (lb/MMBtu) from the most recent three calendar years (CEMs data) based on maximum daily reported data for each unit for NO_x and SO₂ emissions. Days with zero emissions/heat input were not included in these averages.

***The PM₁₀ emission rate is determined from calculating the maximum heat input and annual operating hours.

Boiler 4 is mainly fired on coal and can be fired on natural gas. Fuel oil may be used as a backup fuel, but has not been used in recent years. Boiler 5 is fired on coal, with backup oil firing. Either boiler also may fire ethanol or sludge from the Coors Brewery. Both units are subject to Colorado Regulation 6 Part A and NSPS 40 CFR Subpart D.

III. Units Evaluated for Control

As documented by CENC, these boilers fire low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 3.

Table 3: Coal Specifications (2006 – 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B004	11,703	0.42	9.14
B005	11,833	0.42	9.17

Table 1 lists the units at the CENC facility that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CEMs data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal.

Table 4: Uncontrolled emission factors for CENC BART-eligible sources

Emission Unit	Pollutant	Fuel		
		Natural Gas (lb/MMscf)	Coal (bituminous) (lb/ton)	#2 Fuel Oil (lb/Mgallons)
Boiler 4 & Boiler 5	NO _x	280	8.4	24
	SO ₂	0.6	35 x %S = 14.7*	157 x %S = 67.5*
	PM/PM ₁₀	7.6	PM – 10 x %A = 91.4** PM ₁₀ – 2.3 x %A = 21.0**	PM – 2 PM ₁₀ – 1

*%S = % of sulfur present in coal supply. For example, 35 x 0.42 = 14.7

**%A = % of ash present in coal supply. For example, 10 x 9.14 = 91.4

IV. BART Evaluation of Boiler 4 and Boiler 5

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

CENC identified four SO₂ control options:

Flue gas desulfurization (FGD):

Lime spray dry absorber (SDA or dry FGD)

Dry sorbent injection – Trona (DSI)

SO₂ emission management

The Division also identified and examined additional control options for these units:

Lime or limestone-based (wet FGD)

Emission limit tightening (no control)

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants¹. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO₂ Emissions: A Review of Technologies² evaluates various SO₂ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a “foot print” area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also bound the facility to the north and east. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO₂, the design gas residence time in a SDA is approximately 10 seconds. For Boilers 4 and 5, a SDA vessel for each boiler, not including other associated equipment, would be approximately 35 feet in diameter by 60 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash from the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on either Boilers 4 or 5 (B004/B005).

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO₂ controls on Units 4 and 5. The Division noted:

¹ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

² Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.



Figure 2: Aerial Zoom of CENC Facility

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system.

However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, NO_x to SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boilers 4 and 5.

SO₂ Emissions Management: CENC is subjected to variations in as-received coal sulfur content. Figure 3 provided by CENC shows that there are clearly historical (2000 – 2005) short-term peaks in SO₂ emissions that can be attributed to infrequent deliveries of high-sulfur coal. CENC has no capability or additional storage space on site to store coal or to blend with other lower sulfur coals in order to manage SO₂ emissions to lower levels, and has not had a regulatory need to do so. Once delivered, the facility has no choice but to use the coal delivered before a subsequent lower sulfur shipment can be obtained and burned.

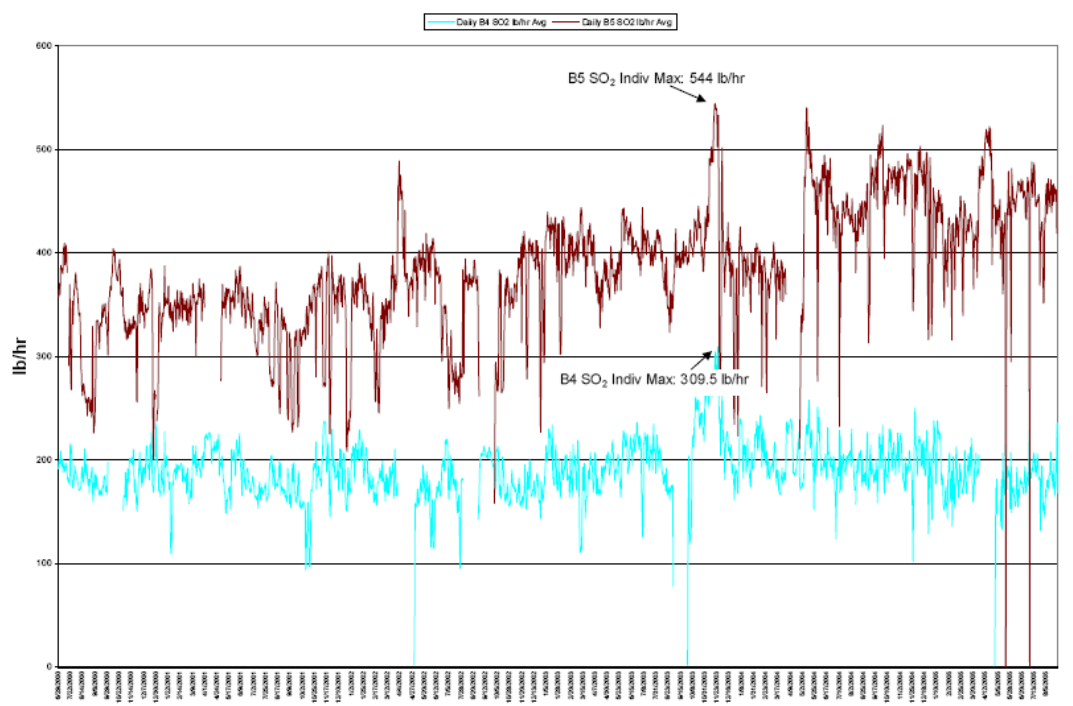


Figure 3: Boilers 4 and 5 SO₂ lb/hour daily average (2000 - 2005)

Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr SO₂ emissions. CENC can employ a variety of options to reduce emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak SO₂ limits. Since these two boilers already have CEMs and stack flow monitors installed, the CEMs could be used to demonstrate continuous compliance. CENC proposes reducing peak levels with limits at 280 lb/hr for Boiler 4 and 500 lb/hour for Boiler 5 on a 24-hour average basis. This option is technically feasible for Boilers 4 and 5.

Emission limit tightening: The Division and CENC conducted technical analyses of sulfur % and heat content in historical coal supplies to determine whether the current SO₂ emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for Boilers 4 and 5.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO₂ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details. The Division notes that for CENC, any RBLC determinations apply for DSI only, since SO₂ emissions management is unit-specific.

DSI: CENC asserts that the maximum SO₂ removal rate that can be achieved to be 65% SO₂ removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals³ and to be conservative since this technology is relatively novel.

SO₂ Emissions Management: Table 5 summarizes current Title V permit limits and projected emission reductions using CENC's proposed limits.

³ Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

Table 5: CENC Boiler 4 and 5 Current vs. Proposed SO₂ Permit Limits and Emissions Reduction

Unit	Current Title V SO ₂ permit limits	Actual Emissions (2000 – 2005)	Actual Emissions (2006 – 2008)	CENC proposed SO ₂ limits
Boiler 4	1892.0 tons/year (approx. 432 lb/hour)	911.8 tons/year (approx. 208 lb/hour)	780.6 tons/year (approx. 178 lb/hour)	280 lb/hour (CEM 24-hr rolling avg.)
	Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)			
	Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)			
Boiler 5	3,416.0 tons/year (approx. 780 lb/hour)	1,954.7 tons/year (approx. 446 lb/hour)	1,406.0 tons/year (approx. 321 lb/hour)	500 lb/hour (CEM 24-hr rolling avg.)
	Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)			
	Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)			
Combined limit	4,888.0 tons/year (approx. 1,116 lb/hour) (PM ₁₀ SIP Agreement)	2,866.5 tons/year (approx. 655 lb/hour)		780 lb/hour (CEM 24-hr rolling avg.)

*Refer to pages A-31, A-34, and A-35 of CENC BART Submittal (July 31, 2006) for detailed SO₂ emission documentation.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) SO₂ emissions. The Division found that the maximum 30-day rolling emission rate was 0.80 lb/MMBtu for Boiler 4 and 0.9 lb/MMBtu for Boiler 5. However, for these small industrial boilers with very limited coal storage capacity, the Division and CENC agree that reviewing sulfur % and heat content is a better basis for determining an appropriate SO₂ emission limit. CENC submitted supplemental information on October 26 and November 10, 2010 to support this methodology. Refer to Table 6 for more details.

Table 6: Coal Supply Analysis for SO₂ Emission Limit

	2006 – 2008
Minimum (Btu/lb)	9.997
Maximum (% Sulfur) (30-day period)	0.52
Theoretical lb/MMBtu	
Boiler 4 Sulfur to SO ₂ conversion averages at 99%*	1.03 (rounded to 1.0)
Boiler 5 Sulfur to SO ₂ conversion averages at 100%*	1.04 (rounded to 1.0)

*CEMs data vs. theoretical

Based on the boiler sulfur to SO₂ conversions, the appropriate emission limit based on actual fuel supply data for the baseline period is 1.0 lb/MMBtu (30-day rolling average). This option serves as assurance that CENC will be able to both continually comply with an appropriate emission limit while simultaneously eliminating future potential emission increases.

Table 7 summarizes each available technology and technical feasibility for SO₂ control.

Table 7: CENC Boilers 4 and 5 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)

Wet FGD	52-98%, median 90% ⁴	Y
Dry FGD (SDA)	70-90% (CENC)	Y
DSI (Trona)	~60%	Y
SO ₂ Emissions Management	30%	Y
Emission Limit Tightening	Minimal	Y

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO₂ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO₂ collected. Detailed capital and annual cost data are presented in "CENC APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI, shown in Table 8.

Table 8: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Ratio (\$/kW)
Colorado Energy Nations – Boiler 4	35	\$1,766,000	\$3,774	\$50.46
Colorado Springs Utilities – Drake Unit 5	51	\$1,746,172	\$2,293	\$34.33

⁴ U.S. EPA, 2000. "Controlling SO₂ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for the U.S. Environmental Protection Agency, Office of Research and Development. Office of Research and Development. Washington, D.C. 20460.

Colorado Energy Nations – Boiler 5	65	\$2,094,000	\$2,485	\$32.22
Colorado Springs Utilities – Drake Unit 6	85	\$2,910,287	\$1,741	\$34.24

The Division considers CENC’s DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.⁵ CENC Boiler 4 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC’s DSI cost estimates.

SO₂ Emissions Management: CENC notes that the costs for implementing a SO₂ Emission Management Plan are based on essentially zero capital cost with increment variable operating costs based on the replacement of a portion of coal boiler capacity with natural gas as needed to reduce historical 24-hour SO₂ peaks. The emission level projected for this alternative was derived from the analysis of historical emission level variability detailed in Figure 3.

The Division verified CENC’s calculated costs for SO₂ Emission Management based on SO₂ hourly CEMs data (06/29/2000 through 01/04/2006), the amount of curtailment that will be required, and average natural gas costs (\$10/MMBtu). In reviewing CENC’s DSI estimate, the Division found that the ratio of annual costs to the total capital costs for the control technology option projected by CENC to be higher than those projected by other facilities that were amortized over the same 20 year time frame. The annualized costs for DSI are about 35% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments⁶. However, CENC is a much smaller facility than the facilities in Arizona, New Mexico, and Oregon, which can significantly increase costs. CENC also clearly followed the Cost Control Manual methodology for estimating operation and maintenance costs. Therefore, the Division did not adjust CENC’s cost estimates.

Emission limit tightening: There are no costs associated with this option. This option is considered equivalent to the “baseline” row in the tables below, and is not considered as a separate cost option.

Table 9, Table 10, Table 11, and Table 12 depict controlled SO₂ emissions and control cost comparisons.

Table 9: Boiler 4 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	780	0.64	0.74

⁵ ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

⁶ Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SO ₂ Emissions Management	0.13	767	0.64	0.74
DSI - Trona	60	312	0.26	0.30

Table 10: Boiler 5 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,406	0.71	0.82
SO ₂ Emissions Management	0.06	1,448	0.71	0.82
DSI - Trona	60	562	0.29	0.33

Table 11: Boiler 4 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)*	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
SO ₂ Emissions Management	1.0	\$44,299	\$43,690	\$43,089
DSI - Trona	468	\$1,766,000	\$3,744	-\$85

Table 12: Boiler 5 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
SO ₂ Emissions Management	0.8	\$65,882	\$78,095	\$92,572
DSI - Trona	844	\$2,094,000	\$2,482	-\$90

Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or “first in time - first in right,” and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado’s

domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.⁷

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART SO₂ control technology consideration on commercially available once-through dry FGD controls, specifically, “lime spray dryers” (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO₂ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO₂ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

SO₂ Emissions Management: The Division has determined that there are not any negative energy or non-air quality related impacts related to the proposed SO₂ emission management scenario.

DSI: CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,⁸ which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

⁷ 2008. “Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District.” Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

⁸ Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol⁹, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO₂ emissions (DSI control) at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 13: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO ₂ Control Scenario	Unit(s)	SO ₂ Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre- Control Days >0.5 dv	Post- Control Days >0.5 dv		Pre- Control Days >1.0 dv	Post- Control Days >1.0 dv	
Max 24- hr	4	0.90	Rocky Mountain	33	---	---	10	---	---
	5	0.98							

⁹ Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

DSI	4	0.258	National Park	33	29	4	10	7	3
	5	0.286		33	28	5	10	7	3
Combo	4&5	0.361 0.392		33	3	30	10	0	10

Table 14: Visibility Results – SO₂ Control Options

Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr	4	0.90	1.07	---	---	---
	5	0.98				
DSI	4	0.258	0.99	0.08	8%	\$21,802,469
	5	0.286	0.94	0.13	12%	\$16,752,000
Combo	4	0.361	0.28	0.79	74%	\$18,393,225
	5	0.392				

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ BART is the following SO₂ emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)
CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

B. Filterable Particulate Matter (PM₁₀)

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Conditions 3.5 and 4.4 require Boilers 4 and 5 to each meet a PM/PM₁₀ emission limit of 0.1 lb/MMBtu. Additionally, Condition 18.1 mandates that

each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 15 shows the most recent stack test data (August 23, 2007 for Boiler 4 and October 10, 2007 for Boiler 5). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: CENC 2007 Stack Test Results

Pollutant	Boiler 4 (lb/MMBtu)	Boiler 5 (lb/MMBtu)
Filterable PM ₁₀	0.013	0.012
PM ₁₀ Control efficiency	98.4%	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

These boilers are subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.¹⁰ As currently proposed, the boilers will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).¹¹

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible

¹⁰ EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

¹¹ EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

(less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The Division has determined that an emission limit of 0.07 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM₁₀ is not needed for CENC Boilers 4 and 5.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CENC identified four NO_x control options:

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combustion modifications/low-NO_x burners (LNB)
- Low-NO_x burners + Separated Overfire Air (LNB+SOFA)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Fuel Switching – Natural Gas
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

CENC estimated that the retrofit SCR systems on Boilers 4 and 5 could achieve 0.06 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Units 4 and 5 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications,

adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case for the CENC boilers. Therefore, high-dust SCR is a technically feasible alternative for CENC Boilers 4 and 5.

SNCR/SNCR+LNB/SOFA: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SNCR is considered a technically feasible alternative for CENC Boilers 4 and 5.

LNB/LNB+SOFA: Low NO_x burners are designed to control fuel and air mixing at each burner in order to create large and more branched flames. Peak flame temperature is thereby reduced, and results in less NO_x formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Combustion, reduction and burnout are achieved in three stages within a conventional low NO_x burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_x are formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed NO_x. In the third stage internal air staging completes the combustion but may result in additional NO_x formation. This however can be minimized by completing the combustion in an air lean environment. Installing LNB with separated OFA may increase carbon monoxide (CO) emissions. LNB/LNB+SOFA are a technically feasible alternative for CENC Boilers 4 and 5.

Low NO_x burners can be combined with other primary measures such as overfire air (OFA) or for even greater NO_x emission reductions, separated overfire air (SOFA). The SOFA system diverts secondary air from the main windbox and injects it into the furnace above the main firing zone. This staged combustion process is one of the first principles of aggressive NO_x reductions. LNB+SOFA is a technically feasible alternative for CENC Boilers 4 and 5.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler¹² and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers¹³ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boilers 4 and 5.

¹² Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

¹³ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu¹⁴. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,¹⁵ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

LNB/LNB+SOFA: CENC estimated that low-NO_x burners (Alstom's Low NO_x Concentric Firing System (LNCFS) System) are capable of reducing NO_x emissions by approximately 10 – 12%, which results in annual emission rates of 0.45 and 0.30 lb/MMBtu for Boilers 4 and 5, respectively. A similar Colorado facility with installed LNB achieves approximately 0.35 – 0.38 lb/MMBtu and estimates an additional 20% reduction if OFA is installed to achieve 0.28 – 0.30 lb/MMBtu. These same burners with Separated Overfire Air were estimated to reduce NO_x emissions by 19 – 35%, resulting in an annualized estimated 0.32 and 0.28 lb/MMBtu for Boilers 4 and 5 respectively.

EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of NO_x emissions.¹⁶ A recent AWMA study noted that LNB with close-coupled OFA firing bituminous coal in tangentially fired boilers achieved, on average, 35% NO_x reduction.¹⁷ However, due to the size and configuration (e.g. furnace dimensions) of the CENC boilers, the Division concurs that the estimated control efficiency rates are reasonable.

SNCR/SNCR+LNB/SOFA: CENC noted in the original BART submittal (July 2006) that SNCR achieves 30 – 50% control, which is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet and the Division's experience. However, when CENC calculated SNCR control efficiency in the November 2009 submittal, it was assumed that LNB+SOFA would be installed beforehand. CENC estimated that SNCR would reduce NO_x emissions 40% with LNB+SOFA installed, for resultant emission rates of 0.19 lb/MMBtu and 0.17 lb/MMBtu for Boilers 4 and 5, respectively. This equates to 62 – 67% reduction depending on the boiler, which

¹⁴ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

¹⁵ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

¹⁶ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹⁷ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

is consistent with EPA's AP-42 emission factor tables (50 – 80%).¹⁸ Therefore, the Division concurs with CENC's control efficiency estimates for LNB+SOFA+SNCR.

The Division conducted a separate analysis regarding stand-alone SNCR installation (without LNB+SOFA installation) for comparison purposes. The Division did not use CENC's original estimate of 40% reduction for SNCR. Instead, the Division estimated control efficiency based on a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study¹⁹ to conservatively approximate that the CENC boilers can achieve 30% control when SNCR is applied.

SCR: CENC, via their vendor, estimates that each boiler will be able to achieve a 0.06 lb/MMBtu emission rate on a 30-day rolling average. CENC estimated control efficiencies on the assumption that LNB+SOFA will already be installed. However, this will not change the overall SCR resultant emission rate.

The Division adjusted this emission rate to be 0.07 lb/MMBtu to be consistent with other Colorado facility submittals and literature review. This adjusted rate equates to 86% control for Boiler 4 and 80% control for Boiler 5. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.^{20,21} Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: CENC Boilers 4 and 5 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners (LNB)	35 – 55%	Y
LNB + OFA	40 – 60%	Y
Overfire air (OFA)	10 – 25% (alone)	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
SNCR+LNB+SOFA	~50 – 80%	Y
Selective catalytic reduction (SCR)	~75 – 90%	Y
ECOR®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

¹⁸ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹⁹ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

²⁰ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²¹ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Cost of Compliance

LNB/LNB+SOFA: CENC contracted Alstom Power to determine total installed costs for low-NO_x burners and separated overfire air. Factors from EPA's Cost Control Manual were used to develop the total annual cost estimate. EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing CENC's estimates, the Division found that the ratio of annual costs to the total capital costs for LNB/LNB+SOFA projected by CENC to be slightly higher than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for LNB for Boilers 4 and 5 are 16.1% and 15.5%, respectively, of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments²². However, the Division and CENC note that the boilers are much smaller than those examined by the EPA. Therefore, the Division concurs with CENC's cost estimates for LNBs. Further, the Division compared recent NESCAUM studies estimating LNB+SOFA for tangentially-fired boilers as between \$420 - \$1,600 per ton NO_x reduced.²³ Both the original and revised CENC cost effectiveness estimates are within the NESCAUM ranges, providing further verification that cost estimates are reasonable. The NESCAUM study did not provide cost estimate ranges for LNB on tangentially-fired boilers.

SNCR/SNCR+LNB+SOFA: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the CENC boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.²⁴ The CENC-estimated SNCR costs for operating expenses are 81% and 86% for Boiler 4 and Boiler 5, respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.²⁵

²² Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

²³ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁴ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

²⁵ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

The cost effectiveness for SNCR on Boilers 4 and 5 is about \$2,900 and \$3,350 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{26,27} EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.²⁸ Although CENC's estimates are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SNCR are reasonable.

SCR: CENC contracted Lutz, Daily, & Brain (LDB) to develop a capital cost estimate. On both boilers, it was determined that the economizers must be moved because there is very little space between the air heater outlet and the current economizer configuration, adding to the capital cost.

Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing \$2,600 - \$5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{29,30} CENC's cost estimates are higher than this range, but the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SCR are reasonable.

Table 17, Table 18, Table 19, and Table 20 depict controlled NO_x emissions and control cost comparisons.

Table 17: CENC Boiler 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	599	0.50		179	
LNB	10	539	0.45	0.515	161	185
SNCR	30	420	0.35	0.400	125	144
LNB+SOFA	35	390	0.32	0.372	116	134
SNCR+LNB+SOFA	61	231	0.192	0.221	69	79
SCR	86	84	0.070	0.080	25	29

²⁶ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁷ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²⁸ EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.” <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

²⁹ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³⁰ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 18: CENC Boiler 5 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	691	0.34		165	
LNB	7	643	0.32	0.368	153	176
LNB+SOFA	18.5	563	0.28	0.322	134	155
SNCR	30	484	0.24	0.277	115	133
SNCR+LNB+SOFA	51	337	0.17	0.193	80	93
SCR	79.6	141	0.07	0.081	34	39

Table 19: CENC Boiler 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	59.9	\$193,433	\$3,227	\$54
SNCR	179.8	\$694,046	\$3,860	\$5
LNB+SOFA	209.8	\$678,305	\$3,234	-\$21
SNCR+LNB+SOFA	368.0	\$1,372,351	\$3,729	\$3
SCR	515.4	\$4,201,038	\$8,150	\$30

Table 20: CENC Boiler 5 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	48.4	\$249,858	\$5,166	\$107
LNB+SOFA	127.3	\$815,829	\$6,383	\$15
SNCR	207.3	\$923,996	\$4,458	(\$24)
SNCR+LNB+SOFA	353.7	\$1,739,825.3	\$4,918	\$3
SCR	550.0	\$6,469,610	\$11,764	\$35

Energy and Non-Air Quality Impacts

LNB/LNB+SOFA: Installing LNB with separated OFA may increase unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Otherwise, there are no known non-air quality

impacts associated with low-NO_x burners and separated overfire air systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/SNCR+LNB+SOFA/SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the case of the CENC boilers, 90 kW per hour, or enough energy to power about 9 homes for a year, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For CENC Boilers 4 and 5, the estimated pressure drop across the catalyst is 7 to 8 inches water column and the total energy consumption is approximately 1,000 kW per hour, or enough energy to power about 100 homes for a year.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to “CENC BART Submittals” for more information.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 21 shows the number of days pre- and

post-control. Table 22 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol³¹, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO₂ emissions at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 21: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr	4	0.67	Rocky Mountain National Park	33	---	---	10	---	---
	5	0.66							
LNB	4	0.45*		n/a					
	5	0.30*		n/a					
SNCR	4	0.35*		n/a					
	5	0.24*		n/a					
LNB+SOFA	4	0.32		33	27	6	10	7	3
NOx Modeled Rate	5	0.28		33	25	8	10	6	4
LNB+SOFA	5	0.24*		n/a					
LNB+SOFA+SNCR	4	0.19		33	27	6	10	7	3
	5	0.17		33	19	14	10	6	4
SCR @ 0.07 lb/MMBtu	4	0.07		33	25	8	10	6	4
SCR @ 0.07 lb/MMBtu	5	0.07		33	19	14	10	6	4

³¹ Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

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Combo	4	0.07		33	3	30	10	0	10
	5	0.07							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “CENC BART Modeling Summary” for more details.

Table 22: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr	4	0.67	1.07	---	---	---
	5	0.66				
LNB	4	0.45*	1.02	0.05	5%	\$3,868,660
	5	0.30*	0.89	0.17	16%	\$1,435,965
SNCR	4	0.35*	0.99	0.07	7%	\$9,507,477
	5	0.24*	0.86	0.21	20%	\$4,358,471
LNB+SOFA	4	0.32	0.99	0.08	7%	\$8,478,816
NO _x Modeled Rate	5	0.28	0.88	0.18	17%	n/a
LNB+SOFA	5	0.24*	0.86	0.21	20%	\$3,848,252
LNB+SOFA+SNCR	4	0.19	0.96	0.11	10%	\$12,475,919
	5	0.17	0.82	0.25	23%	\$7,101,328
SCR @ 0.07 lb/MMBtu	4	0.07	0.89	0.18	17%	\$23,734,677
SCR @ 0.07 lb/MMBtu	5		0.75	0.31	29%	\$20,669,680
Combo	4	0.07	0.28	0.79	74%	\$18,393,225
	5	0.07				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “CENC BART Modeling Summary” for more details.

Step 6: Select BART Control

The Division and CENC worked together to determine a “flexible” BART option for Boilers 4 and 5. CENC initially proposed this option in its’ prehearing statement on September 15, 2010. This option incorporates both an individual limit (lb/MMBtu) for each boiler or a combined average (lbs/hr) for both boilers for a 30-day rolling average period. CENC submitted supplemental information regarding a “flexible” BART plan on October 19, 2010 to the Division, citing the preamble to the BART regulations to ‘consider allowing sources to ‘average’ emissions across any set of BART-eligible emission units within a fence line, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible source.’ This determination adheres to the language in the BART preamble.

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Boiler 4 is the following NO_x emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NO_x burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Boiler 5 is the following NO_x emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NO_x burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.

- Boiler 5: \$4,918 per ton NO_x removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Public Service Company – Comanche Station, Units 1 and 2**

I. Source Description

Owner/Operator:	Public Service Company
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	Unit 1: 10100226 Unit 2: 10100222
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two tangentially fired (Units 1 and 3) and one wall-fired (Unit 2)

Comanche Station is located at 2005 Lime Road in Pueblo, CO, which is located within Pueblo County. Comanche Station commenced operation in the early 1970s. The facility originally consisted of two coal fired boilers, driving steam turbines used to generate electricity and associated support equipment (cooling and service water towers and coal and ash handling equipment). Unit 1 commenced operation in 1972 and serves a generator rated at 325 MW. Unit 2 commenced operation in 1975 and serves a generator rated at 335 MW. The boilers burn sub-bituminous coal from the Powder River Basin (PRB) as fuel and use natural gas for startup, shutdown and flame stabilization.

In August of 2004, Public Service Company of Colorado (PSCo) proposed to construct and operate a new coal-fired boiler (Unit 3) at Comanche Station. As part of that project, PSCo proposed to install control devices on the existing units. PSCo entered into a Settlement Agreement in December 2004 with various citizen groups and voluntarily agreed to install additional control devices and take emission limitations. In addition to the new unit (Unit 3), additional support equipment was proposed including a cooling tower, coal and ash handling equipment and various support equipment for the control device reagents (e.g., silos for lime, recycle ash and sorbent). Construction permits for the project were issued on July 5, 2005.

Low NO_x burners with over-fire air and a lime spray dryer were installed in November 2008 on Unit 1 and low NO_x burners with over-fire air and a lime spray dryer were installed in November 2007 on Unit 2. Operation of the SO₂ controls did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. Unit 3 commenced operation in January 2010.

Units 1 and 2 are considered BART-eligible because the units were in existence on August 7, 1977 and not in operation prior to August 7, 1962 and are located at a fossil-fuel-fired steam electric plant greater than 250 MMBtu/hr, with the potential to emit of more than 250 tons or more of any visibility impairing air pollutant (NO_x, SO₂, PM₁₀). The results of the initial BART modeling analysis, indicated that the visibility impairment exceeded 0.5 deciviews (98% percentile -

8th high), at federal Class I areas. Therefore, since Units 1 and 2 “cause or contribute” to visibility impairment BART applies to these units.

Table 1 below lists the units at Public Service Company Comanche Station that are subject to BART and are addressed in this BART analysis as well as the control efficiency of the controls currently installed on Units 1 and 2 (note SO₂ and NO_x controls were installed within the baseline period).

Table 1: Comanche Units 1 and 2 Technical Information

	Unit 1	Unit 2
Placed in Service	December 1973	November 1975
Boiler Rating, MMBtu/Hr for coal	3,531	3.482
Electrical Power Rating, Gross Megawatts	325	335
Description	Combustion Engineering Tangentially Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.	Babcock and Wilcox Wall-Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.
Air Pollution Control Equipment	PM/PM ₁₀ – Baghouse – Installed 1993 NO _x – Low NO _x Burners with Over-Fire Air – Installed November 2008 SO ₂ – Lime Spray Dryer – Installed November 2008, fully operational 6/3/09	PM/PM ₁₀ – Baghouse – Installed 1991 NO _x – Low NO _x Burners with Over-Fire Air - Installed November 2007 SO ₂ – Lime Spray Dryer – Installed November 2007, fully operational 1/10/09
Emissions Reduction (%)*	NO _x – 62.7% SO ₂ – 76.1% PM – 99.7% PM ₁₀ – 99.0%	NO _x – 44.1% SO ₂ – 81.9% PM – 99.8% PM ₁₀ – 99.3%

*Emissions Reduction estimated by comparing pre-control 2005 – 2007 CAMD data (2005 – 2006 for NO_x on Unit 2) to controlled 2009 data. For PM/PM₁₀, uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See “Comanche APCD Technical Analysis” for further details. Not based on actual testing.

PSCo submitted a BART analysis to the Division on August 1, 2006, with revisions to that analysis submitted on August 15, 2006 (editorial corrections), October 19, 2006 and January 8, 2007. At the Division’s request, PSCo submitted additional information dated January 19, February 24, March 1, April 12, April 21, May 25, July 14, and July 22, 2010. These documents are included as “PSCo BART Submittals”.

II. Source Emissions

In PSCo’s August 1, 2006 BART application, baseline emissions were based on calendar year 2004 and 2005 emissions. Several years have passed since the

original BART submittal, in which the Division has updated modeling and technical analyses. Additionally, PSCo, as detailed in Table 1, has installed air pollution controls on both units at Comanche in 2008. Therefore, the Division used years 2009 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database.

Controls were installed on Unit 2 in November 2007 and controls were installed on Unit 1 in November 2008. While the SO₂ controls did not commence full operation until 2009, the NO_x controls did commence operation upon installation. In addition, PSCo has indicated that lime was initially injected into the lime spray dryers in December 2008 for Unit 1 and July 2008 for Unit 2 in order to test the controls. The baseline emissions are summarized in Table 2.

Table 2: PSCo Comanche Units 1 & 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO _x	1,511	0.124	2,349	0.165
SO ₂	1,557	0.128	1,244	0.091
PM ₁₀	80	0.007***	40	0.005***

*Using daily CEMs data from 2009 calendar year (CAMD data).

**The Division calculated average emission rate or used the CAMD reported rate (lb/MMBtu) from the 2009 calendar year (CAMD data) based on average daily reported data for each unit for NO_x and SO₂ emissions.

***The PM₁₀ emission factor is determined from the most recent Title V permit compliance stack tests (March 2003).

III. Units Evaluated for Control

According to PSCo's August 1, 2006 BART application sub-bituminous coal from the Powder River Basin (PRB), Belle Ayr mine in Wyoming is typically used as fuel. The characteristics of the Belle Ayr PRB coal presented in the August 1, 2006 BART application are presented below in Table 3.

Table 3: Comanche Station Coal Specifications (From August 1, 2006 BART Application)

Coal Mine/Region	PRB – Belle Ayr
Coal Rank Classification	Sub-bituminous
Proximate Analysis	
H ₂ O (Moisture weight %)	29.9
Ash (weight %)	4.6
Sulfur (weight %)	0.31
Ultimate Analysis	
Nitrogen (weight percent %)	0.68
Other	
Heating Value (HHV Btu/lb)	8,550

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Comanche BART-eligible sources¹

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Unit 1	8.4	9.5	46.6	10.7
Unit 2	7.4	9.5	46.6	10.7

*SO₂ and PM/PM₁₀ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006-2009). Please refer to “Comanche APCD Technical Analysis” for more details.

Emission limitations that apply to these boilers are as follows:

- Colorado Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu, for each boiler.
- Colorado Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu, for each boiler.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_x emissions to 0.40 lb/MMBtu and 0.46 lb/MMBtu, both on an annual average basis for Units 1 and 2, respectively.
- 40 CFR Part 60 Subpart D §§ 60.44(a)(3) and 60.45(g)(3), as adopted by reference in Colorado Regulation No. 6, Part A limits NO_x emissions to 0.7 lb/mmBtu, on a 3-hr rolling average. Applies to Unit 2 only.
- Colorado Construction Permits 11PB859, IA, mod 1 (Unit 2) and 04PB1429, IA (Unit 1) both issued July 5, 2005)
 - NO_x emissions shall not exceed 0.20 lb/MMBtu, on a 30-day rolling average, for each unit.
 - SO₂ emissions shall not exceed 0.12 lb/MMBtu, on a 30-day rolling average, for each unit.

These limits shall be met no later than 180 days after the initial startup of the SO₂ and NO_x control equipment for each unit or by July 1, 2009, whichever is earlier

- NO_x emissions from both Units 1 and 2 together shall not exceed 0.15 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)
 - SO₂ emissions from both Units 1 and 2 together shall not exceed 0.10 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)
- PSCo shall begin calculating compliance with these limits no later than 180 days after initial startup of the SO₂ and NO_x control equipment for the last unit.
- Filterable PM emissions shall not exceed the following limits: Unit 1: 393 tons/quarter and 1,546 tons/yr and Unit 2: 390 tons/quarter and 1,525 tons/yr.

¹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.
<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

- Filterable PM₁₀ emissions shall not exceed the following limits: Unit 1: 363 tons/quarter and 1,423 tons/yr and Unit 2: 357 tons/quarter and 1,403 tons/yr.
- SO₂ emissions from Units 1 and 2 together shall not exceed 939.3 tons/quarter and 3,686 tons/yr.
- NO_x emissions from Units 1 and 2 together shall not exceed 1,564.4 tons/quarter and 6,142 tons/yr.

The above limitations take effect 180 days after initial startup of the last control device for the last unit or upon startup of Unit 3, whichever is earlier. Note that the quarterly limits apply for the first year of operation only.

IV. BART Evaluation of Units 1 and 2

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA’s BART Guidelines², electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Comanche Units 1 and 2 if technically feasible. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

The current Construction Permit limits are depicted in Table 5.

Table 5: Comanche Units 1 & 2 SO₂ Operating Permit Limits

	SO ₂ limits (lb/MMBtu)	
	30-day rolling	Annual rolling (combined)
Units 1 & 2	0.12	0.10

As indicated in EPA’s BART Guidelines [70 FR 39171], for dry-FGD (i.e., LSDs) the following scrubber upgrades should be considered.

- Use of performance additives

² EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

In addition to upgrades to the scrubbers, the Division also asked PSCo to look into the feasibility of achieving a lower 30-day SO₂ emission limitation with the existing controls (i.e., SO₂ emission limit tightening) and/or other potential upgrades, including improved operations and maintenance, use of more reagent, and keeping more spare parts on hand.

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO₂ upgrade analysis to the Division on May 25, 2010 and additional information on July 22, 2010 regarding potential upgrades for the LSDs installed on Comanche Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Dry FGD Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants³. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

As indicated previously, as part of a permitting action to construct and operate a new unit (Unit 3) at Comanche Station, PSCo committed to installing both NO_x and SO₂ controls on Units 1 and 2. Permits were issued on July 5, 2005 for Units 1 and 2 which addressed the controls and the associated emission limitations that these units would be required to meet prior to commencing operation of the proposed new unit. To that end, a lime spray dryer (LSD) was installed on Unit 1 in November 2008 and a LSD was installed on Unit 2 in November 2007. Full operation of the LSDs commenced in June 2009 and January 2009 for Units 1 and 2, respectively. Table 1 indicates that the LSDs are achieving

³ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

emission reductions at approximately 76% for Unit 1 and 82% for Unit 2 in comparison with the permit limits⁴ depicted in Table 5. It should be noted that since July 1, 2009, when the SO₂ limits became applicable, Unit 1 is achieving emission reductions at about 86.5% and Unit 2 at 85.3%. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits. Therefore, since Comanche Units 1 and 2 are equipped with existing FGD and are achieving removal efficiencies greater than 50%, the BART analysis need not consider replacement of the SO₂ controls but should consider upgrades to the existing FGD.

-Use of performance additives: The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO₂. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO₂ reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO₂ removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO₂ removal. Therefore, this upgrade is not technically feasible. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO₂ removal and therefore warrants no further consideration.

-Use of more reactive sorbent: All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve SO₂ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Hayden.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO₂. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied

⁴ Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO₂ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO₂ due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO₂ removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO₂ removal; there are no known acceptable reagents without side effects that would allow additional SO₂ removal in the dry scrubbing systems present at Comanche Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

Increase the pulverization level of sorbent: PSCo indicated that Colorado's dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. Although PSCo notes that there have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. Their experience has been that there is no SO₂ removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. PSCo considers that they already uses the best available grinding technologies and that there are no improvements that can be done to further decrease lime particle size to reduce SO₂ emissions. The Division agrees that upgrades to grinding technologies are unlikely to produce additional SO₂ reductions and therefore no further consideration is warranted.

Engineering redesign of atomizer or slurry injection system: The Comanche dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO₂ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO₂ removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO₂ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO₂ removal level, although some have improved wear life and reduced maintenance costs. Given that the LSDs installed on Units 1 and 2 were installed recently, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO₂ removal.

Emission limit tightening: In addition to considering upgrades to the existing FGDs on Units 1 and 2, the Division asked PSCo to consider whether tightening of the existing BART 30-day limits was feasible. Comanche Units 1 and 2 are subject to the following SO₂ emission limitations:

Table 6: Comanche Units 1 & 2 SO₂ Emission Limitations

	SO ₂ Emission Limitations				
	Emission Rate (lb/MMBtu)			Mass Emissions (tons)	
	3-hr rolling	30-day rolling*	365-day rolling	Quarterly	Annual
Unit 1	1.2	0.12	N/A	N/A	N/A
Unit 2	1.2	0.12	N/A	N/A	N/A
Units 1 and 2 Together	N/A	N/A	0.10	939	3.686

*Included as limits in the BART construction permit (07PB0112B) issued September 12, 2008.

In their May 25, 2010 submittal, PSCo addressed the feasibility of tightening their 30-day SO₂ emission limits. In their submittal, PSCo indicated that based on operating experience for Comanche Units 1 and 2, as well as other PSCo units equipped with LSDs, that the primary factor affecting the SO₂ control efficiency for short-term averages are startups, equipment malfunctions and low load operations. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below the minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. PSCo indicated that this had actually occurred while operating Comanche Unit 2 and Valmont Unit 5 and resulted in extended maintenance outages in order to clean the scrubbers. In addition, during unit start-ups, it can take anywhere from between 12 and 24 hours to get the inlet scrubber temperature up to the level necessary for safe slurry injection. The scrubber can be run at higher levels of SO₂ reduction in order to offset the effects of a startup during a 30-day period, but the more startups that occur during that 30 day permit the more difficult it will become to offset the higher emissions during startup. PSCo also indicated that during low load operations, especially in the winter, the inlet temperature at the baghouse approaches the minimum acceptable level, subsequently lowering the overall SO₂ control efficiency during low load operations. PSCo indicated that due to the increased use of wind resources, the boilers will be required to cycle more frequently to accommodate intermittent wind resources and therefore, the units will run at low loads more frequently and as a result the SO₂ reduction levels will be lower during those times.

The Division reviewed available SO₂ emission data from CAMD for 2009 and for part of 2010 (January – October 2010). As previously indicated although the LSDs were installed in 2007 and 2008, they only recently commenced full operation, Unit 1 in June 2009 and Unit 2 in January 2009. As a result there is limited data available to determine post-control achievable emissions. In addition, if as PSCo indicates, the units are cycled more frequently to accommodate increased wind energy resources, it is not clear how well the data represents future operation. In addition, since the LSDs came on line recently, PSCo has limited operating experience with these units. Although PSCo has

other units that are equipped with LSDs and have been operating those units with LSDs for some time (e.g., Valmont Unit 5, Hayden Units 1 and 2), those units are not using PRB coal. Comanche Units 1 and 2 represent the first units in PSCo's system with LSDs that are firing PRB coal as fuel. After startup of the LSDs in 2009 both units have had a number of days indicating zero emissions, presumably due to a unit shutdown. In addition, in many cases, emissions data shows that frequently for one or more days following these events, the daily SO₂ emission rate is well above 0.12 lb/MMBtu. Unit 1 averaged 0.07 lb/MMBtu during this period, with a maximum rate of 0.10 lb/MMBtu in December 2009. Unit 2 has had several months (December 2009, May 2010, October 2010) during the 2009 – 2010 timeframe that either exceed or are within 0.01 lb/MMBtu of the existing 0.12 lb/MMBtu 30-day rolling average limit. A review of annual data showed that in 2009, the SO₂ annual average from both units was approximately 0.11 lb/MMBtu. In 2010 thus far, the annual average is 0.07 lb/MMBtu, but it is important to note that it is apparent from the data on both units historically that lower inlet temperature(s) to the scrubber(s) in the winter months result in increased SO₂ emissions.

As explained above, the Division projects 30-day rolling SO₂ emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer or greater to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy. Therefore, the Division concurs that tighter 30-day rolling average and annual average SO₂ emission limit is not feasible at this time for either unit.

Additional equipment and maintenance: As discussed in the emission limit tightening section, PSCo reviewed actual operating experience on Comanche along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO₂ control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO₂ emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO₂ by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum

acceptable levels, thus lowering overall SO₂ control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

PSCo sent confirmation to the Division on July 22, 2010 that an extra scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers. The Division concurs with this assessment. Therefore, since it is not technically feasible to install an extra scrubber module, additional spare atomizer parts and increased operating and maintenance will not result in decreased SO₂ emissions. The Division concludes that this option is not technically feasible for Comanche Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO₂ reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct a control effectiveness evaluation.

Step 4: Evaluate Impacts and Document Results

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO₂ reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct an evaluation of the cost, energy and non-air environmental impacts, and remaining useful life.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various potential emission rates. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 6 shows the number of days pre- and post-control. Table 7 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol⁵, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) and other BART-eligible units are held constant at pre-

⁵ Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

Table 6: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

Table 6: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area									
SO2 Control Scenario	Unit(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.75	Great Sand Dunes National Park	60	---	---	27	---	---
	2	0.74							
Dry FGD	1	0.12		60	49	11	27	21	6
	2			60	50	10	27	21	6
Dry FGD	1	0.10		60	48	12	27	21	6
	2			60	49	11	27	21	6
Dry FGD	1	0.08*		n/a					
	2			n/a					
Dry FGD	1	0.07		60	48	12	27	20	7
	2			60	48	12	27	21	6
Combo	1	0.12		60	4	56	27	1	26
	2								

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Comanche BART Modeling Summary” for more details.

Table 7: Visibility Results – SO₂ Emission Rates

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.75	2.05	---	---
	2	0.74			
Dry FGD	1	0.12	1.71	0.35	17%
	2		1.72	0.33	16%
Dry FGD	1	0.10	1.69	0.36	17%
	2		1.71	0.35	17%
Dry FGD	1	0.08*	1.68	0.37	18%

	2		1.69	0.36	18%
Dry FGD	1	0.07	1.67	0.38	18%
	2		1.69	0.37	18%
Combo	1	0.12	0.36	1.69	82%
	2				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Comanche BART Modeling Summary” for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ BART is the following existing SO₂ emission rates:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)
Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO₂ limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

B. Filterable Particulate Matter (PM₁₀)

Comanche Units 1 and 2 are each equipped with fabric filter baghouses to control PM/PM₁₀ emissions. In a baghouse, the particle laden flue gas passes through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow. The bags are periodically cleaned when too much filter cake builds up and increases the pressure drop across the fabric filter. A baghouse is considered the best particulate matter control device particularly for boilers burning low sulfur western coals.

As indicated previously in Table 1, estimated control efficiencies for the baghouse are over 99% for both PM and PM₁₀. These control efficiencies are based on the allowable post-control emissions rate of 0.1 lb/MMBtu for PM and 0.092 lb/MMBtu for PM₁₀ (assumes PM₁₀ = 92% of PM). Actual performance test data shown in Table 8 indicates that PM emissions from Comanche Units 1 and 2 are well below the allowable levels. The results of performance tests conducted in 2003 indicate the following emission rates:

Table 8: Comanche Units 1 and 2 Stack Test Results (2003)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM ₁₀ *	0.003	0.003
PM ₁₀ Control efficiency	99.6%	99.6%

*PM₁₀ = 0.92 x PM

The BART construction permit (07PB0112B) issued on September 12, 2008 for Comanche Units 1 and 2 set a PM emission limitation of 0.03 lb/MMBtu, which is more

stringent than the limit of 0.1 lb/MMBtu that currently applies to these units. Although test results indicate that emissions below the 0.03 lb/MMBtu BART limit are certainly achievable, the 2003 performance test is just one 3-hour test and does not necessarily represent achievable emission rates over all operating conditions. Therefore, the Division considers that the PM limit set the BART permit is still appropriate. Using the allowable post-control PM BART limit of 0.03 lb/MMBtu BART limit, the control efficiency of the baghouses are indicated in Table 8 above.

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM₁₀ is not needed for Comanche Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

In various submittals with respect to installing additional NO_x controls on Comanche Units 1 and 2, PSCo looked at two options:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

As part of this BART evaluation, the Division identified and examined the following additional control options for these units:

- Powerspan Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Rotating Opposed Fired Air (ROFA), ROFA with SNCR
- Low NO_x Burners (LNB) with Separated Overfire Air (SOFA)
- Reburning
- Emission limit tightening

Since low NO_x burners with over-fire air (LNB-OFA) were recently installed on Units 1 and 2 (November 2008 for Unit 1 and November 2007 for Unit 2), the Division considers that further upgrades to the LNB-OFA would provide little in the way of additional reductions and therefore upgrades to the existing LNB-OFA were not considered.

Step 2: Eliminate Technically Infeasible Options

Selective non-catalytic reduction (SNCR): The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and either injected ammonia or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_x reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. The necessary temperature range is 1,600 - 2,100°F. SNCR can typically achieve NO_x reductions on the order of 40-70%.

PSCo has indicated that SNCR is feasible for Unit 1. According to their April 6, 2009 submittal, PSCo conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. The testing was done following the installation of LNB-OFA to determine if additional reductions could be achieved. Testing was conducted primarily at full load over a seven-day period using a single-level urea based-SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 °F, which exceeds the optimal temperature for the technology. During the test periods, NO_x reductions were less than 10%, and in some cases during testing, an actual increase in NO_x emissions was seen. Therefore, PSCo considers that SNCR is not feasible on Unit 2 and the Division concurs.

Selective Catalytic Reduction (SCR): SCR systems are the most widely used post-combustion NO_x control technology on pulverized coal-fired boilers. The SCR process is an add-on control which uses a catalyst bed and ammonia injection for removal of NO_x emissions. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. SCR systems can achieve NO_x reductions in the range of 60 – 90%. SCR is technically feasible for Comanche Units 1 and 2.

Powerspan Electro-Catalytic Oxidation (ECO)®: The Powerspan electrostatic oxidation process (ECO)® is an integrated air pollution control process that achieve reductions in multiple pollutants from coal-fired power plants, included NO_x, SO₂, mercury and fine particulate matter (particulate matter less than 2.5 microns). The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse and consists of an ECO reactor (to oxidize pollutants), absorber vessel (saturates and cools the flue gas, removes SO₂, NO₂ and oxidized mercury) and a wet electrostatic precipitator (removes acid aerosols, air toxics and fine particulate matter). To date the ECO® system has been used on a slipstream (50 MW) from a 156 MW boiler equipped with an

electrostatic precipitator and low NO_x burners⁶. While the technology may be considered commercially available, it has only been demonstrated on the portion of the exhaust of a smaller boiler. Therefore, the Division considers that this technology is not feasible.

Rich Reagent Injection (RRI): Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. RRI is similar to SNCR but the reagent at the lower furnace at significantly higher temperatures (2400 – 3100°F).⁷ The RRI process was originally developed for coal-fired cyclone boilers and the Division is not aware that RRI has been utilized on other types of coal-fired boilers. Therefore, the Division considers that RRI is technically infeasible for Comanche Units 1 and 2.

Rotating Opposed Fire Air (ROFA) and ROFA with SNCR: With ROFA air is injected into the furnace first which breaks up the fireball and creates a swirling air flow to increase combustion. The swirling air results in better mixing of the fuel and air and distributes the temperature more evenly throughout the furnace, which improves combustion and reduces NO_x emissions. Typical NO_x reductions from ROFA alone range from 45 – 60 percent.⁸ As indicated in Table 3, the estimated NO_x reductions for Units 1 and 2 with LNB-OFA are over 55% percent. Since ROFA is not expected to provide more NO_x reductions than the current controls on Units 1 and 2, further review of ROFA is not warranted.

That same ROFA system can be used to inject urea or ammonia into the furnace. However, since the NO_x reduction efficiency for the Comanche Unit 1 and 2 LNB-OFA systems are comparable to ROFA, combining ROFA and SNCR is not likely to result in NO_x reductions significantly above the level achieved by the Unit 1 existing LNB-OFA in conjunction with SNCR (note that SNCR is not feasible on Unit 2). Therefore, ROFA-SNCR will not be considered further.

Low NO_x Burners (LNB) with Separated Over Fire Air (SOFA): Over-fire air (OFA) is a combustion control technology where a portion of the total combustion air is diverted from the burners and injected later in the combustion process, typically above the combustion zone. There are specific OFA configurations that are typically associated with tangentially-fired boilers, close-coupled to the burner, separated from the burner and combination. The high end of the NO_x reduction ranges for the various OFA configurations for tangentially fired boilers are lower than the range for LNB-OFA on wall-fired units.⁹ Since alternate OFA configurations will not result in significant NO_x reductions beyond LNB-OFA, they will not be considered further.

⁶ http://www.powerspan.com/FirstEnergy_ECO.aspx

⁷ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009.

<http://www.ftek.com/apcRRI.php>

⁸ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

⁹ Srivastava et. al, September 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association, volume 55, pg 1370.

Reburning: In reburning, a portion of the total heat input (up to 25%) is provided by injecting a secondary (reburning) fuel above the main combustion zone. Combustion of the reburning fuel results in hydrocarbon fragments, which react with a portion of incoming NO_x which form nitrogen containing compounds which are ultimately reduced to N₂. The fuel used for reburning need not be the primary fuel. Natural gas has frequently been used as reburning fuel, as there are more issues to consider with coal as the reburn fuel (e.g. particle size). In general reburning can achieve greater than 50% NO_x reduction, but many reburning demonstration projects are no longer operating.¹⁰ Reburning can be used in conjunction with other NO_x control technologies, such as LNB-OFA, SCR and SNCR. Given that the control efficiency with reburning alone is similar to the NO_x reduction efficiency of Comanche Units 1 and 2 with LNB-OFA (see Table 4), the Division considers that further evaluation of reburning is not warranted.

Emission limit tightening: The Division conducted technical analyses to determine whether the current NO_x emission limit(s) could be more stringent based on actual emissions after installation of the low NO_x burners with over-fire air (Unit 1 – December 2008 – Oct. 2010 and Unit 2 - December 2007 – October 2010). This option is technically feasible for both units.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals¹¹, determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. To be conservative, the Division projected an annual average emission rate at 15% for Comanche to determine control efficiencies and annual reductions.

The Division considered that two additional NO_x reduction options warranted further consideration. Although some of the identified control technologies were not considered technically infeasible, they offered similar NO_x reduction levels that are already achieved with the LNB-OFA installed on Comanche Units 1 and 2. The two additional NO_x reduction technologies warranting further review are SCR and SNCR (Unit 1 only). \

SNCR: In their April 20, 2010 submittal, PSCo indicated that a NO_x emission rate of 0.10 lb/MMBtu was achievable on Unit 1. The Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 29.5%. This control effectiveness estimate is roughly equivalent to EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers.

SCR: In their April 20, 2010 submittal, PSCo indicated that a NO_x emission rate of 0.07 lb/MMBtu was achievable on both Units 1 and 2. Again, the Division calculated the control effectiveness based on the difference between the baseline (2009) and expected

¹⁰ Srivastava et. al, pp 1371-1372.

¹¹ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

emission rate. This calculated control effectiveness for Comanche Unit 1 is 51% and for Comanche Unit 2 is 63%. These control efficiencies are lower than EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.^{12,13} However, the resultant emission rate of 0.07 lb/MMBtu is consistent with the rates cited in the AWMA study. PSCo and the Division recognize and concur that the lower initial emission rates of 0.124 and 0.165 lb/MMBtu for Units 1 and 2 respectively result in reduced SCR control efficiencies.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from current NO_x emissions. The Division found that the maximum 30-day rolling emission rate for Unit 1 from December 2008 – October 2010 was about 0.15 lb/MMBtu and the average 30-day rolling rate was around 0.13 lb/MMBtu. For Unit 2, from December 2007 to October 2010, the maximum 30-day rolling emission rate was about 0.17 lb/MMBtu and the average 30-day rolling rate was around 0.17 lb/MMBtu. As explained above, the Division projects 30-day rolling NO_x emission rates to be approximately 15% higher than annual average emission rates. The uncertainty of evaluating a “maximum” emission rate warrants a similar 15% buffer to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy.

The Division also found that for 2009, the annual average emission rate for both units was approximately 0.15 lb/MMBtu, and a review of January – October 2010 found that annual average emission rate thus far is about 0.16 lb/MMBtu. The existing annual limit of 0.15 lb/MMBtu for both units is an appropriate NO_x emission limit at this time. Therefore, appropriate NO_x emission limits assuming existing low NO_x burner with over-fire air technology for Units 1 and 2 are 0.20 lb/MMBtu on a 30-day rolling average for each unit and 0.15 lb/MMBtu annual average for both units. A re-evaluation of these emission limits will occur for the next regional haze planning period. Table 9 summarizes each available technology and technical feasibility for NO_x control.

Table 9: Comanche Units 1 and 2 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
SNCR	20 – 50%	Y
SCR	50 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO _x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed

¹² EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹³ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

SNCR and SCR: In their January 19, 2010 submittal, PSCo provided cost information associated with SNCR for Unit 1 and SCR for both Units 1 and 2. PSCo used EPA’s Coal Utility Environmental Costs (CUECost) workbook model to estimate capital and ongoing operating and maintenance costs. The costs were then levelized at 2016/2017 dollars based on a 20-yr life to determine annual costs. The levelized costs were reported in 2016/2017 dollars on the assumption that SNCR would be installed by 2015 and SCR would be installed by 2016, with an additional year to optimize operation of the new control equipment. PSCo submitted the inputs and outputs from CUECost to the Division in a March 1, 2010 e-mail to the Division. The levelized cost methodology and results were provided in Xcel internal memos dated February, 24, 2010 (submitted to the Division via e-mail on March 1, 2010) and April 16, 2010 (submitted via e-mail to the Division on April 21, 2010). According to PSCo’s April 20, 2010 submittal, the cost per ton for SNCR for Unit 1 was estimated to be \$ 4,342/ton and the cost per ton for SCR was estimated to be \$15,173/ton for Unit 1 and \$9,558/ton for Unit 2.

Although the Division does not dispute the levelized annual costs for SNCR and SCR, the baseline emission rates used to determine the cost per ton for the incremental reduction are not appropriate. For Unit 1, PSCo presumed baseline emission rates of 0.12 lb/MMBtu for SNCR and 0.13 lb/MMBtu for SCR and for Unit 2 PSCo presumed a baseline emission rate of 0.18 lb/MMBtu. The Division has set a baseline period of 2009. The baseline emission rates are shown in Table 1.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.¹⁴ The PSCo-estimated SNCR costs for operating expenses is about 69% for Comanche Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.¹⁵

¹⁴ ICAC, 2000. Institute of Clean Air Companies, Inc. “White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions.” Washington, D.C. 2000.

¹⁵ EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.”
<http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

The Division-calculated cost effectiveness for SNCR on Unit 1 is \$3,644 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 1) achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{16,17} It should be noted that PSCo is estimating resultant emission rates much lower than 0.30 lb/MMBtu for this boiler. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.¹⁸ PSCo's estimates are above this range. However, the Division concludes that PSCo's cost estimates for SNCR are reasonable due to the low input NO_x emission rate and degree of retrofit difficulty.

SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing \$2,600 - \$5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{19,20} In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 15.3% is just slightly higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.²¹ PSCo's cost estimates are above the NESCAUM study ranges due to the lower control efficiencies explained earlier. The Division concludes that PSCo's cost estimates for SCR are reasonable due to low emission reductions and retrofit difficulties.

Table 10, Table 11, Table 12, and Table 13 depict controlled NO_x emissions and control cost comparisons. Refer to "Comanche APCD Technical Analysis" for more details.

Table 10: Comanche Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,511	0.124	

¹⁶ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

¹⁷ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

¹⁸ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet."

<http://www.epa.gov/ttn/catc/dir1/fsncr.pdf>

¹⁹ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁰ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²¹ Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SNCR*	29.5	1,065	0.087	0.100
SCR**	51	740	0.061	0.070

*Determined based on difference between baseline (2009) and PSCo's expected emission rates

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 11: Comanche Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	2,349	0.165	
SCR**	63	869	0.061	0.070

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 12: Comanche Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
SNCR	445.6	\$1,624,100	\$3,644	---
SCR	770.4	\$12,265,014	\$15,920	\$32,762

Table 13: Comanche Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
SCR	1,480	\$14,650,885	\$9,900	---

Energy and Non-Air Quality Impacts

SNCR and SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam

in some cases. 100 – 300 kW is enough energy to power about 10 homes for a year. These energy requirements are minimal and were confirmed by PSCo in the January 19, 2010 submittal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. PSCo noted that the retrofit installation of an SCR typically requires the installation of new, larger induced draft fans to over-come the additional pressure drop created by the SCR catalyst. In addition, although PSCo acknowledged that the energy requirements for SCR are more significant than SNCR they did not quantify these impacts since the increase in house power usage are included in the ongoing operating costs for each technology in the CUECost model.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

PSCo did identify the change in operating mode for the coal fired boilers as more wind energy is brought onto the PSCo system as a non-air quality impact that would affect any NO_x control technology. PSCo noted that typically coal-fired boilers are operated as base-loaded units and as such they typically run at full load 24-hours a day, with only minor load reductions at night when demand is lower or during off-peak periods in the spring and fall. However, with more wind resources replacing other conventional power sources, the load may be dropped further since demand for power is less. Therefore, the load on coal-fired units may be further reduced, particularly during peak wind generating periods. PSCo considers that operating these units at lower loads may affect the NO_x control technologies and result in lower NO_x reductions than those that would be seen at high loads.

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

In their January 19, 2010 submittal PSCo indicated that the remaining useful life of Comanche Units 1 and 2 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol²², to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO₂ and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.40	Great Sand Dunes National	60	---	---	27	---	---
	2	0.53							
NO _x @	1	0.20		60	57	3	27	24	3

²² Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

0.20 lb/MMBtu			Park						
NOx @ 0.20 lb/MMBtu	2	0.20		60	51	9	27	21	6
SNCR @ 0.10 lb/MMBtu	1	0.10		60	51	9	27	22	5
SNCR not feasible	2	n/a		60	n/a	n/a	27	n/a	n/a
SCR @ 0.07 lb/MMBtu	1	0.07		60	51	9	27	21	6
SCR @ 0.07 lb/MMBtu	2	0.07		60	47	13	27	18	9
Combo	1 2	0.07		60	4	56	27	1	26

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Comanche BART Modeling Summary” for more details.

Table 15: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Impact Improvement from new LNB (2009)	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(Δ dv)	(%)	(\$/dv)
Max 24- hour	1 2	0.40 0.53	2.05	---	---	---	---
New LNB (2009)	1	0.20	1.90	0.16	n/a	8%	n/a
	2	0.20	1.75	0.31	n/a	15%	n/a
SNCR	1	0.10	1.79	0.26	0.11	13%	\$6,175,284
SNCR not feasible	2	n/a					
SCR	1	0.07	1.76	0.30	0.14	14%	\$41,576,317
	2	0.07	1.58	0.47	0.17	23%	\$31,172,095
Combo	1 2	0.07	0.36	1.69	n/a	82%	n/a

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Comanche BART Modeling Summary” for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein , the state has determined that NO_x BART is following existing NO_x emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)

Comanche Unit 2: 0.15 lb/MMBtu (combined annual average for units 1 & 2)
0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NO_x burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined based on the high cost/effectiveness ratios to not be reasonable coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2**

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO₂) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfired air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO₂ and low-NO_x burners with overfired air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Table 1 lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

Table 1: Craig Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	1980	1979
Gross Boiler Rating, MMBtu/Hr for coal	4,417	4,417
Electrical Power Rating, Net Megawatts	428	428
Description	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.
Air Pollution Control Equipment	PM/PM ₁₀ – Pulse Jet Fabric Filter Baghouse NO _x – Ultra-low NO _x Burners with Over-Fire Air SO ₂ – Wet Limestone FGD All updated control equipment commenced full operations in 2004.	PM/PM ₁₀ – Pulse Jet Fabric Filter Baghouse NO _x – Ultra-low NO _x Burners with Over-Fire Air SO ₂ – Wet Limestone FGD All updated control equipment commenced full operations in 2004.
Emissions Reduction (%)*	NO _x – 23.8% /53.9% SO ₂ – 77.6%/93.8% PM – 99.6% PM ₁₀ – 99.4%	NO _x – 29.5%/54.7% SO ₂ – 79.5%/93.8% PM – 99.9% PM ₁₀ – 99.5%

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For PM/PM₁₀, uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See “Craig APCD Technical Analysis” for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and in existence in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as “Tri-State BART Submittals”.

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or “Baseline” Emissions”, to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses.

Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado’s Air Pollutant Emission Notices and EPA’s CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO _x	5,190	0.278	5,372	0.271
SO ₂	970	0.052	982	0.050
PM ₁₀	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO₂ emissions.

***The PM₁₀ emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 1&2 will continue to burn “bituminous-like” coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	ColoWyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H ₂ O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Craig BART-eligible sources¹

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Unit 1	12	16.9	73.9	17.0
Unit 2	12	16.1	71.1	16.4

*SO₂ and PM/PM₁₀ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to “Craig APCD Technical Analysis” for more details.

IV. BART Evaluation of Units 1 and 2

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA’s BART Guidelines², electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:

- Elimination of bypass reheat
- Installation of liquid distribution rings
- Installation of perforated trays
- Use of organic acid additives
- Improve or upgrade scrubber auxiliary equipment
- Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

Table 5: Craig Units 1 & 2 SO₂ Operating Permit Limits

	SO ₂ limits (lb/MMBtu)			Reduction (%) Required 90-day rolling
	3-hr rolling	30-day rolling	90-day rolling	
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

¹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

² EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA’s presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division’s request, Tri-State submitted a SO₂ upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State examined potential upgrades to the Craig wet FGD systems, with the following results:

-Elimination of bypass reheat: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-Installation of liquid distribution rings: Liquid distribution rings were not installed during the YEP; however, Tri-State determined that installation of perforated trays, described below, accomplished the same objective.

-Installation of perforated trays: Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO₂ by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-Use of organic acid additives: Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO₂ removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:

1. DBA has not been tested at the very low inlet SO₂ concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on SO₂ removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO₂ removal.

-Improve or upgrade scrubber auxiliary equipment: YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO₂ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO₂ removal rates.

2. Forced oxidation within the SO₂ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.

3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.

5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.

6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO₂ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.

7. Instrumentation and controls were modified to support all of the new equipment.

-Redesign spray header or nozzle configuration: The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO₂ emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit 1	0.081	0.052
Craig Unit 2	0.093	0.079

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in \$/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol³, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO₂ emissions at 0.10 lb/MMBtu (wet FGD).

³ Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							
Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Craig BART Modeling Summary” for more details.

Table 8: Visibility Results – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Craig BART Modeling Summary” for more details.

Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling SO₂ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An SO₂ limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

B. Filterable Particulate Matter (PM₁₀)

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM ₁₀	0.006	0.005
PM ₁₀ Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM₁₀.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

Tri-State identified five options for NO_x control:

New/modified Low NO_x Burners (LNBs) with Overfired Air (OFA) system (next generation)

Advanced OFA system or Rotating overfired Air (ROFA)

Neural network system combustion controls

Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)[®]

Rich Reagent Injection (RRI)

Coal reburn +SNCR

Craig Units 1 and 2 currently have ultra-low NO_x burners with over-fire air (ULNBs+OFA) installed (2004) for NO_x control purposes.

Step 2: Eliminate Technically Infeasible Options

LNBs with OFA Upgrades: Tri-State contracted with ACT to modify the existing Craig 1&2 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-NO_x Babcock & Wilcox 4Z burners such as those in use at Craig Units 1 and 2. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that “to give a guaranteed NO_x reduction, a lot more information is required.” LNBs modifications with OFA upgrades appear to be technically feasible for Craig Units 1 and 2.

Advanced OFA system – rotating overfired air system (ROFA): ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mototec could not give Tri-State a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load⁴. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: Tri-State received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit’s distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. Tri-State states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

⁴ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler⁵ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfired air. Rich reagent injection was developed for cyclone boilers⁶ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

⁵ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

⁶ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu⁷. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,⁸ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: Tri-State noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: Tri-State noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control.

⁷ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

⁸ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

B&V explains that the reduction in control efficiency is due to the difference between “design criteria” versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State’s extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy’s Eastlake and W.H. Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA’s SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu⁹ or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).¹⁰ EPA’s AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State’s estimate to 0.07 lb/MMBtu based on the reasoning above.

⁹ Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

¹⁰ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners/Ultra-low NO _x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfired air (OFA)	5-40%	Y – installed
Ultra-Low NO _x Burner (ULNB) Upgrade/Refinements	0 – 2% (Tri- State)	Y
Neural network system	0 – 5% (Tri- State)	Y
SNCR	~15%	Y
Rotating overfired air (ROFA)	45 – 65%	N
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x burner upgrades: Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low NO_x burners with overfired air. Ultra-low NO_x burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.¹¹ Tri-State estimates that the initial cost of combustion control refinement at about \$2,200,000 with an annualized 20-year cost of \$122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

¹¹ Bryk and Kleisley, 2000. “First Commercial Application of DRB-4Z™ Ultra-Low NO_x Coal-Fired Burner.” Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

Neural network system: Tri-State did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that Tri-State contacted.¹² It is unknown why Tri-State will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about \$800,000 with an annualized 20-year cost of \$280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.¹³ The Tri-State-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.¹⁴

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately \$4,877 and \$4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing \$590 - \$1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{15,16} It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.¹⁷ On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately \$2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from Tri-State. The costs for these two items are higher than other Colorado facility estimates.

¹² NeuCo White Papers and Case Studies. <http://www.neuco.net/library/case-studies/default.cfm> and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NO_x Emission Control Cost and Technical Feasibility Information."

¹³ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

¹⁴ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

¹⁵ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

¹⁶ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

¹⁷ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing \$1,700 - \$3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{18,19 20,21} It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately \$7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,190	0.278	
Combustion control refinements	2	5,087	0.273	0.31
Neural network system	5	4,931	0.264	0.30
SNCR	15	4,412	0.236	0.27
SCR	78.0	1,142	0.061	0.070

¹⁸ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

¹⁹ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²⁰ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²¹ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 13: Craig Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,372	0.271	
Combustion control refinements	2	5,264	0.265	0.31
Neural network system	5		0.257	0.30
SNCR	15	4,566	0.230	0.27
SCR	74	1,397	0.070	0.081

Table 14: Craig Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Combustion control refinements	104	\$122,000	\$1,175	\$1,175
Neural network system	260	\$280,000	\$1,079	\$1,015
SNCR	779	\$3,797,000	\$4,877	\$6,776
SCR	4,048	\$25,036,709	\$6,184	\$6,394

Table 15: Craig Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Combustion control refinements	107	\$122,000	\$1,136	\$1,136
Neural network system	269	\$280,000	\$1,043	\$980
SNCR	806	\$3,797,000	\$4,712	\$4,712
SCR	3,975	\$25,036,709	\$6,298	\$6,702

Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol²², to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels.

²² Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO₂ emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.352	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.345							
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230		207	194	13	123	123	0
SCR	1	0.07		207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
Combo	1	0.07							
	2	0.07		207	57	150	123	12	111

Table 17: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hour	1	0.352	3.73	---	---	---
	2	0.345				
SNCR	1	0.236	3.42	0.31	8%	\$12,327,922
	2	0.230	3.42	0.31	8%	\$12,327,922
SCR	1	0.07	2.72	1.01	27%	\$24,887,384
	2	0.08	2.79	0.94	25%	\$26,691,207
Combo	1	0.07		2.56	69%	
	2	0.07	1.17			\$19,537,034

Step 6: Select BART Control

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMBtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that they can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan. The criteria in Chapter 6 guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the notable visibility improvements, the reasonable dollars per ton control costs, and the support of Tri-State for installation of SCR at Units 1 and 2.

- Unit 1: \$6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: \$6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's decision to approve Colorado's Regional Plan.

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In Table 19 below, an assumed amortization period of eight years of operation²³ is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected²⁴. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	779	\$6,172,522	\$7,928
SCR	4,048	\$64,106,699	\$15,835

Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	779	\$4,755,842	\$6,109
SCR	4,048	\$41,476,535	\$10,245

Based on this assessment, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life; or

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

²³ Operation period begins calendar year 2018 (December 31, 2017).

²⁴ EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NO_x emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until closing or conversion to natural gas. Additionally, an annual NO_x limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NO_x reductions and other environmental co-benefits compared to the 2014 BART determination.

Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 *or* cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NO_x emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NO_x emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NO_x limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Colorado Springs Utilities – Drake Plant**

I. Source Description

Owner/Operator: Colorado Springs Utilities
 Source Type: Electric Utility Steam Generating Unit
 SCC (EGU): 10100202
 Boiler Type: Three Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas (Units 5, 6, and 7)

The facility is located at 700 South Conejos Street in Colorado Springs. This facility consists of three (3) steam driven turbine/generator units (Units 5, 6, and 7) and the associated equipment needed for generating electricity. These units fire coal as the primary fuel and use natural gas for backup and startup. The facility also includes the various processes necessary to handle the coal and ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control of PM and PM₁₀ at appropriate point sources. In addition, the coal is treated with chemical additives to reduce fugitive emissions. Table 1 depicts technical information for each boiler at the Drake Plant.

Table 1: Drake Boilers Technical Information

	Unit 5	Unit 6	Unit 7
Placed in Service	October 28, 1962	July 27, 1968	June 14, 1974
Boiler Rating, MMBtu/Hr for coal	548	861	1,336
Electrical Power Rating, Gross Megawatts	51	85	142
Description	Riley Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 548 MMBtu/Hr w/ coal, 514 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 861 MMBtu/Hr w/ coal 850 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 1336 MMBtu/Hr w/Coal, 1310 MMBtu/Hr w/ NG.
Air Pollution Control Equipment	Reverse-Air Fabric Filter Baghouse- installed in May 1998	Reverse-Air Fabric Filter Baghouse – installed in September 1978	Reverse-Air Fabric Filter Baghouse– installed in November 1993
Inherent Special Features	Low NO _x burners – placed in service in May 1998	Low NO _x burners – placed in service in March 1998	Low NO _x burners – placed in service in October 1999
Monitoring Equipment	COM CEMs for SO ₂ , NO _x ,	COM CEMs for SO ₂ , NO _x ,	COM CEMs for SO ₂ , NO _x ,

	CO ₂ , and stack gas flow rate	CO ₂ , and stack gas flow rate	CO ₂ , and stack gas flow rate
Emissions Reduction (%)*	NO _x – 54.7% SO ₂ – None PM – 99.7% PM ₁₀ – 98.6%	NO _x – 52.8% SO ₂ – None PM – 99.6% PM ₁₀ – 98.2%	NO _x – 57.7% SO ₂ – None PM – 99.8% PM ₁₀ – 99.1%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM₁₀. For NO_x estimates, CAMD data was used to calculate reduction. See “Drake APCD Technical Analysis” for further details. Not based on actual testing.

Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in “NO_x and SO₂ Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants” Submittal provided on February 20, 2009 as well as additional information upon the Division’s request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010. These documents are all provided as “CSU Drake BART Submittals”.

Regulations that apply to these boilers are as follows:

- State Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu.
- State Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_x emissions to 0.46 lb/MMBtu of heat input on an annual average basis.
- No other annual emission limitations or State Regulations since units are Grandfathered¹.

II. Emissions for Units 5, 6, & 7

CSU estimated that a realistic depiction of anticipated annual emissions for Boilers 5, 6, and 7, or “Baseline Emissions”, to be conservative, was the average of two previous years (2004, 2005) of emissions data in the August 1, 2006 analysis. Several years have

¹ Colorado Department of Public Health and Environment Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emission Notice Requirements 5 CCR 1001-5 Part G.IV states: “A source existing before the adoption of the first Colorado Air Quality Control Act and the date of its implementing regulations of February 1, 1972, is not required to obtain a permit. This revision is intended to clarify the date prior to which existing sources are considered “grandfathered” and exempt from permit requirements.”

passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado’s Air Pollutant Emission Notices and EPA’s CAMD database as applicable. These emissions are summarized in Table 2.

Table 2: CSU Boilers 5, 6 and 7 Baseline Emissions

Pollutant	Boiler 5		Boiler 6		Boiler 7	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO _x	768	0.38	1,413	0.42	2,081	0.39
SO ₂	1,269	0.63	2,785	0.82	4,429	0.83
PM ₁₀	27	0.01***	58	0.02***	55	0.01***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO₂ emissions.

***The PM₁₀ emission rate is determined from the Title V permit compliance stack test. These values are as follows: Drake #5 – 0.0132 lb/MMBtu; Drake #6 – 0.0186 lb/MMBtu; Drake #7 – 0.0111 lb/MMBtu.

III. Units Evaluated for Control

As documented by CSU, these boilers fire a variety of coal types, including coal from the southern Powder River Basin (PRB, located in Wyoming), ColoWyo coal (from northwestern Colorado), 20-Mile Foidel Creek coal (northwestern Colorado), and West Elk coal (western Colorado). The specifications for these coals are listed below in Table 3 (averaged from 2006 – 2008). Table 4 lists the 2006 – 2008 averaged APEN-reported coal characteristics for each boiler. Table 4 is not based on percent of various coals fired, but instead based on the Division’s Air Pollutant Emission Notice (APEN) database. Sources submit annual emissions data using APENs. Due to equipment limitations, these boilers cannot achieve full load on PRB-sourced coal and instead fire a blend of the above listed coals. The ratio of PRB was discussed in the initial BART analysis submitted by CSU in an effort to demonstrate that firing sub-bituminous coal may have a minimal effect (if any) on a boiler’s NO_x emissions. In fact the data suggested at that time that 100% sub-bituminous coal had no effect on NO_x emissions for some of the boilers. CSU notes that this effect may be boiler specific. The difference in sulfur content and resultant SO₂ emissions was not discussed in the initial BART analysis. Colorado’s BART guidance (Regulation No. 3, Part F, Section IV.B.1.f) states that sources may include an evaluation of representative characteristics of coals from sources they reasonably expect to use, so that these characteristics may be considered in a particular BART limit.

Table 3: Drake Plant Coal Specifications (2004 – 2005)

Coal Mine/Region	Southern PRB	Colowyo	20-Mile Foidel Creek	West Elk
Coal Rank Classification	Sub-bituminous	Sub-bituminous, Class A	Bituminous	Bituminous

As Received Analysis				
H ₂ O (Moisture %)	27.11	17.42	9.62	7.55
Ash (%)	4.64	5.71	11.93	8.71
Sulfur (%)	0.21	0.37	0.52	0.45
Nitrogen (%)	0.69	1.35	1.57	1.30
Heating Value (HHV Btu/lb)	8,805	10,392	11,084	12,266

Table 4: Coal Specifications (2006 – 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Boiler #5	9,798	0.36	8.14
Boiler #6	10,749	0.47	10.38
Boiler #7	11,117	0.50	11.14

Table 1 lists the units at Colorado Springs Utilities Drake Plant that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 5. The factors are based on firing bituminous coal for conservative estimates.

Table 5: Uncontrolled emission factors for CSU Drake BART-eligible sources²

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Boiler #5	22	13.6	81.5	18.7
Boiler #6	22	18.0	103.8	23.9
Boiler #7	22	18.8	111.4	25.6

*SO₂ and PM/PM₁₀ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 4.

A. Sulfur Dioxide (SO₂)

Step 1: Identify All Available Technologies

CSU identified one control option for Units 6 and 7:

Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)

CSU identified two control options for Unit 5:

Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)

Dry sorbent injection – Trona (DSI)

The Division also identified and examined additional control options for these units:

Lime/limestone-based wet FGD – all units

Emission limit tightening – Unit 5 (no control)

Step 2: Eliminate Technically Infeasible Options

² EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber that uses slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that results in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants³. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a “foot print” area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks. The plant is bounded to the north by West Cimarron Street, to the west by federal Interstate Highway 25 and Fountain Creek, to the east by Conejos Street, and the south by Fountain Creek (as the Interstate and the Creek curve to the southeast). Train tracks (the Drake rail spur) also bound the facility to the north, south, and west. Along the east side of the plan (immediately east of Conejos Street) is the main railroad line. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the Drake Plant, due to locations as well as pollution control retrofits for particulate matter. As figure 2 indicates, the square footage available to accommodate a FGD for Unit 5 is 3,025 ft² and Units 6 & 7 is 8,346 ft² (or about 4,000 ft² per unit). The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. Demolition and site reconfiguration would be required for FGD systems on these units and has been included in the cost analysis provided by Drake. CSU determined that it is technically feasible to install a dry FGD on Unit 5, Unit 6 and Unit 7.

³ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

⁴ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.



Figure 1: Drake Plant Physical Boundaries



Figure 2: Drake Plant Detailed View

The Division conducted site visits and determined:

- Unit 5
 - CSU determined dry FGD controls are technically feasible although available physical space was severely constrained and some demolition and site reconfiguration would be required; the Division conducted a site visit and determined that dry FGD controls were not appropriate considering the space constraints, shown in Figure 1 and Figure 2. Therefore control effectiveness and impacts for dry FGD are not evaluated in this analysis.
 - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Unit 5.
- Units 6 and 7
 - Dry FGD controls are technically feasible for Units 6 and 7.
 - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Units 6 and 7.

It is worth noting that CSU-Drake is currently testing a new, innovative non-traditional wet scrubber control system that appears to be as effective, if not more effective, at controlling SO₂ emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system, called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4. Regarding the applicability of the NeuStream process to Drake Unit 5, the Division notes that this technology is not commercially available at this time. CSU has not determined if this technology is feasible for this smaller unit. However, the Division will re-assess this technology in the next Regional Haze planning period.

Although the technology being tested by CSU does not technically meet the definition of “available” as set forth in the BART rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber. This process will be required to meet the emission limits established for the LSD technology established in this BART determination. Regardless of the technology utilized, Drake has to meet the LSD-based BART limits within 5 years of EPA approval of the BART

SIP. CSU will test the NeuStream system until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO₂ BART limits for Units 6 and 7.

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO₂ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the Unit 5 airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO₂ which has a reddish-brown color. This conversion of NO to NO₂ can create a brown plume from the stack which could create opacity compliance issues. Due to variability of boiler configurations, coal composition, NO_x to SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ removal real-time testing. Therefore, DSI is technically feasible for Drake Plant Unit 5. The Division assumes that this same technology is also then technically feasible for Unit 6 and Unit 7.

Emission limit tightening (unit 5 only): The Division conducted technical analyses to determine whether the current SO₂ emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for all units. However, the Division only examined this option for Unit 5 since when this option was examined; preliminary SO₂ determinations had already been established for all units. Unit 5 was the only unit where the emission limit could potentially be achieved with the assumption of no control.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Units 5, 6, and 7 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO₂ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Dry FGD (LSD): Controlling SO₂ Emissions: A Review of Technologies⁵ indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Drake Power Plant, typically <0.5% as detailed in Table 3, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Additionally, achievement of a 90% removal rate on a long-term basis would require levels of equipment redundancy that may not be feasible to locate at a congested site such as the Drake Power Plant.

DSI: Based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved to be 60% SO₂ removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) SO₂ emissions. The Division found that the maximum 30-day rolling emission rate for Unit 5 was 0.83 lb/MMBtu. As explained above, the Division projects 30-day rolling SO₂ emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer to be applied in this case, especially due to the fact that the Drake facility has limited coal storage capacity and blends four different types of coals. Therefore, an appropriate SO₂ emission limit assuming no control technology for Unit 5 is 0.9 lb/MMBtu on a 30-day rolling average.

Table 6 summarizes each available technology and technical feasibility for SO₂ control.

⁵ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Table 6: Drake Units 5, 6, and 7 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	81 – 90%	N – Unit 5 Y – Units 6 & 7
DSI	60% (CSU)	Y

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

LSD/DSI: CSU submitted cost estimates for LSD systems on Units 5, 6 and 7 in the original BART submittal on August 1, 2006 and updated refined cost estimates on March 29, 2007. CSU provided cost estimates for the DSI system evaluated on Unit 5 on May 10, 2010.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,⁶ shown in Table 7.

Table 7: CSU-Drake SO₂ LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group (\$/ton SO ₂ Removed)	CSU Refined Cost Estimate (\$/ton SO ₂ Removed (Control System))	Cost Differential
Unit 6 –	\$2,399	\$2,579 - \$2,981	+ 8% – 24%

⁶ EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO₂ Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

85 MW			
Unit 7 – 142 MW	\$1,796	\$2,140 - \$2,694	+ 19% - 50%

EPA’s study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Units 6 and 7 using various cost updates from the 2006 timeframe. Drake has reflected the costs of retrofitting a facility that is already congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. Therefore, the Division considers CSU’s updated cost information for the LSD controls on these units to be reasonable estimations for the cost of control.

The Division considers this cost to be within a reasonable cost range that is comparable to other Colorado facility submittals.⁷ Therefore, the Division did not adjust CSU’s cost estimates. CSU only submitted DSI cost information for Unit 5. The Division scaled this cost information for Units 6 and 7 in Table 9, Table 10, and Table 11. Please see “Drake APCD Technical Analysis” for more details.

For dry FGD, CSU estimated a removal rate of 83.3% based on a worst-case coal sulfur concentration of 0.9 lb/MMBtu, baseline years 2004 and 2005, and a resulting emission rate at the BART presumptive limits of 0.15 lb/MMBtu. The Division adjusted this removal rate using the baseline SO₂ emissions from Table 2 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 76 – 90% that meets or exceeds BART presumptive limits for Units 6 and 7, and exceeds the limits for Unit 5. This range allows the Division to determine the most reasonable BART limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See “Division APCD Technical Analysis” for more details.

Emission limit tightening: There are no costs associated with this option for unit 5. This option is considered equivalent to the “baseline” row in the tables below, and is not considered as a separate cost option.

Table 8 illustrates resultant SO₂ emissions for each technically feasible control option. Table 9, Table 10, and Table 11 show the SO₂ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 2. The Division analyzed both annual and 30-day rolling average limits. The Department’s experience with power plants suggests that the maximum 30-day rolling average SO₂ emission rate is approximately 5% higher than the annual average emission rate.

⁷ ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

Table 8: Units 5, 6, and 7 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions								
		Unit 5			Unit 6			Unit 7		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)
Baseline	---	1,269	0.63		2,785	0.82		4,429	0.83	
DSI	60	508	0.25	0.26	1,114	0.33	0.34	1,771	0.33	0.35
Dry FGD (LSD)	82				501	0.15	0.15	797	0.15	0.16
Dry FGD (LSD)	85				418	0.12	0.13	664	0.12	0.13
Dry FGD (LSD)	90				279	0.08	0.09	433	0.08	0.09

Table 9: Drake Unit 5 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
DSI	762	\$1,340,663	\$1,760	\$1,760

Table 10: Drake Unit 6 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
DSI	1,671	\$2,234,438	\$1,337	\$1,337
Dry FGD (LSD) @ 82% control	2,284	\$6,186,854	\$2,709	\$6,540
Dry FGD (LSD) @ 85% control	2,368	\$6,647,835	\$2,808	\$5,517
Dry FGD (LSD) @ 90% control	2,507	\$7,452,788	\$2,973	\$5,780

Table 11: Drake Unit 7 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
DSI	2,657	\$3,732,826	\$1,405	\$1,405
Dry FGD (LSD) @ 82% control	3,632	\$8,216,863	\$2,263	\$4,602
Dry FGD (LSD) @ 85% control	3,764	\$8,829,321	\$2,345	\$4,610
Dry FGD (LSD) @ 90% control	3,986	\$9,898,382	\$2,483	\$4,828

Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or “first in time - first in right,” and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado’s domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.⁸

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART SO₂ control technology consideration on commercially available once-through dry FGD controls, specifically, “lime spray dryers” (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO₂ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO₂ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA’s own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber.

⁸ 2008. “Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District.” Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

There will be a greater volume of material being landfilled. A LSD scrubber consumes a significant amount of water, as detailed in Table 12.

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
6	68	35.7
7	100	53.0

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in **Error!**

Reference source not found. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO₂ when measured on a per MW-h basis.

Table 13: LSD Energy Replacement Costs

Unit	Replacement capacity cost (\$/kW-yr)	Differential energy cost (\$/MW-h)
6/7	44	35

This information, including detailed capital and annual cost data, are provided as “CSU Drake BART Submittals”. CSU originally generated costs using EPRI’s FGD Cost model.⁹ This model uses specific unit data to calculate the cost of controlling emissions, and is considered to be accurate within $\pm 30\%$. The refined cost estimates from March 2007 were further extrapolated to account for retrofit difficulties, annual inflation, and also hyperinflation of certain construction commodities and energy. The March 2007 submittal also incorporates budgetary quotes from vendors for the major pieces of equipment as well as noting the need for a non-recycling LSD due to the ash removal system’s operation at a very high capacity factor. As depicted in Figure 3, a non-recycling LSD would eliminate slurry solids; instead the FGD solids (removed in the baghouse) are immediately disposed.

⁹ EPA’s BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO₂ removal equipment as of the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

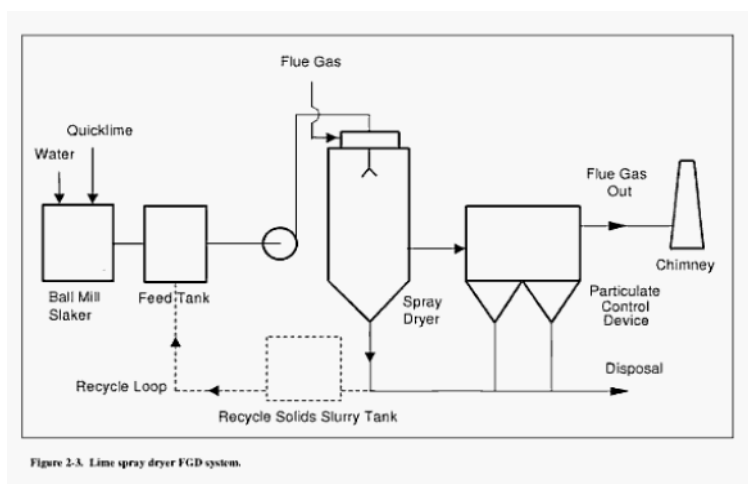


Figure 3: Lime Spray Dryer (LSD) Schematic¹⁰

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,¹¹ which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

¹⁰ EPA, 2000. "Controlling SO₂ Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 12.

¹¹ Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol¹², to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5. The Division modeled Drake Unit 5 for 0.12 lb/MMBtu as a theoretical examination of the potential impacts of lower emission limits on that unit.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO ₂ BART Control Limit	Unit(s)	SO ₂ Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre- Control Days >0.5 dv	Post- Control Days >0.5 dv		Pre- Control Days >1.0 dv	Post- Control Days >1.0 dv	
Max 24- hr SO ₂ rates	5	0.943	Rocky Mountain National Park	34	---	---	17	---	---
	6	0.997							
	7	0.994							
DSI	5	0.251		34	32	2	17	14	3

¹² Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

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	6	0.328		34	32	2	17	14	3
	7	0.333		34	31	3	17	13	4
dry FGD (LSD)	5	0.120		n/a					
	6	0.120		34	31	3	17	14	3
	7	0.120		34	28	6	17	12	5
dry FGD (LSD)	6	0.100		34	31	3	17	14	3
	7	0.100		34	28	6	17	12	5
dry FGD (LSD)	6	0.070		34	31	3	17	14	3
	7	0.070		34	28	6	17	12	5
Combo	5	0.321							
	6	0.120		34	1	33	17	0	17
	7	0.120							

Table 15: Visibility Results – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr SO ₂ rates	5	0.943	1.84	---	---	---
	6	0.997				
	7	0.994				
DSI	5	0.251	1.72	0.12	6%	\$14,673,714
	6	0.328	1.65	0.18	10%	\$15,903,206
	7	0.333	1.55	0.29	16%	\$16,765,140
dry FGD (LSD)	5	0.120	n/a			
	6	0.120	1.59	0.24	13%	\$27,470,391
	7	0.120	1.45	0.39	21%	\$22,697,484
dry FGD (LSD)	6	0.100	1.59	0.25	14%	n/a
	7	0.100	1.44	0.40	22%	n/a
dry FGD (LSD)	6	0.070	1.58	0.26	14%	\$28,999,176
	7	0.070	1.42	0.41	22%	\$23,967,026
Combo	5	0.321	0.25	1.59	86%	n/a
	6	0.120				
	7	0.120				

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ BART for Unit 5 is the following SO₂ emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ BART for Unit 6 and Unit 7 is the following SO₂ emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSDs). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

The emission rates for Units 6 and 7 provide 85% SO₂ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: \$2,808 per ton SO₂ removed; 0.24 deciview of improvement
- Unit 7: \$2,345 per ton SO₂ removed; 0.39 deciview of improvement

B. Filterable Particulate Matter (PM₁₀)

Drake Units 5, 6, and 7 are each equipped with reverse-air fabric filter baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP107 Condition 2.4.2 requires Units 5, 6, and 7 to conduct performance testing for PM₁₀ annually. While the emission in Condition 2.4 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 16 shows the most recent stack test data (June 14, 2006). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 16: Drake 2006 Stack Test Results

Pollutant	Unit 5 (lb/MMBtu)	Unit 6 (lb/MMBtu)	Unit 7 (lb/MMBtu)
Filterable PM ₁₀	0.0132	0.0186	0.0111

PM ₁₀ Control efficiency	98.6%	98.3%	99.0%

A Division review of EPA’s RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to “Division RBLC Analysis” for more details.

The State determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM₁₀) for the three units represents the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA’s BART Guidelines, a full five-factor analysis for PM/PM₁₀ is not needed for Drake Units 5, 6, and 7.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Selective Non-Catalytic Reduction (SNCR)
- Ultra-low NO_x burners and Over-fire air (ULNB+OFA)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load¹³. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Units 5, 6, and 7. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

¹³ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Units 5, 6, and 7. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N₂ rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed¹⁴. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Units 5, 6, and 7.

ULNBs: Each unit has low NO_x burners installed, shown in Table 1. These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Units 5, 6, and 7.

ULNB+OFA: Since ULNB and OFA are each technically feasible options and would be installed separately for Units 5, 6, and 7, it stands to reason that ULNB+OFA is technically feasible option for Units 5, 6, and 7.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 5, 6, and 7 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air

¹⁴ IEA Clean Coal Centre: Clean Coal Technologies – Air Staging for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion

quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Drake Units 5, 6, and 7.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Drake Units 5, 6, and 7. This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for the three boilers at the Drake Plant.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler¹⁵ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers¹⁶ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 5, 6, and 7.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's BART analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost (\$/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a

¹⁵ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

¹⁶ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

technically feasible alternative for Drake Units 5, 6, and 7. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu¹⁷. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,¹⁸ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Drake Units 5, 6, and 7 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 20% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of NO_x emissions.¹⁹ The low NO_x burners currently achieve about 50 – 56% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.²⁰ Therefore, the Division concurs with CSU's additional 20% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20 – 30% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at the Drake boilers. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.²¹ Therefore, the Division concurs with CSU NO_x reduction estimates for ULNBs.

¹⁷ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

¹⁸ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

¹⁹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²⁰ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

²¹ U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory.

<http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf>

ULNB+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. CSU noted in the February 2009 submittal that ULNB are assumed to achieve 20% efficiency *assuming* OFA is already installed (at 0.35 lb/MMBtu for each unit). The Division is employing a different baseline that CSU originally utilized (e.g. NOx emissions prior to consideration of OFA). The Division requested additional information from CSU to verify that the 20% ULNB assumption is still valid for all units. CSU noted that Units 6 and 7 will likely be able to achieve the 20% reduction (using the Division's higher NOx emission baseline). However, Unit 5 has an older technology coal mill and other technical issues and would not be able to achieve 20% reduction. Unit 5 has an older mill (ball-type pulverizers vs. the hammermills present at Units 6 and 7), which limits the level of coal fineness. In addition, Unit 5 is a smaller boiler than the other units. In light of these specific technical feasibility issues, the Division used 10% additional reduction efficiency for ULNBs for Unit 5. Therefore, the overall control efficiencies for ULNB+OFA in combination for the three units are 28% for Unit 5 and 36% for Units 6 and 7 respectively.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study²² to conservatively approximate that the Drake boilers can achieve 30% control when SNCR is applied.

SCR: CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2004 – 2005 baseline emissions (or 0.07 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions, but kept the resultant 0.07 lb/MMBtu constant. This control efficiency is consistent with EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.^{23,24}

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 17 summarizes each available technology and technical feasibility for NO_x control.

Table 17: Drake Units 5, 6, and 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners (LNB)	50 -56%	Y – installed

²² Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

²³ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²⁴ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

LNB + OFA	60 – 81%	Y (LNBs are installed on each unit)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO _x burners (ULNBs)	26 – 32%	Y
ULNB+OFA	28 – 36%	Y
Selective non-catalytic reduction (SNCR)	~ 30%	Y
Selective catalytic reduction (SCR)	75 – 90%	Y
ULNB/SCR layered approach	75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake boilers in 2004. The cost estimates were generated using EPRI's IECCost model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NO_x Controls for Existing Utility Boilers,"²⁵ OFA alone ranges from \$410 - \$1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Drake's estimated OFA NO_x reductions (20%). The estimates in Table 18, Table 20, and Table 22 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 19, Table 21, and Table 23. The Division considers CSU's estimated costs more than

²⁵ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."
<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

reasonable, with ULNBs under \$1,000/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.^{26, 27}

ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the Drake boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.²⁸ A similar Colorado facility estimated operating expenses at approximately 81 – 86%.²⁹ Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.³⁰

The Division used information from a similar facility submittal to determine approximate SNCR costs for the Drake boilers since CSU did not have SNCR information.³¹ The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Drake boilers in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 5, 6, and 7 ranges from \$2,700 to \$4,400 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{32,33}

²⁶ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/nox-2000.pdf

²⁷ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁸ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

²⁹ CENC, 2009. "NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

³⁰ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsncr.pdf>

³¹ CENC, 2009. "NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

³² Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³³ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.³⁴ Although the resulting cost estimates for the Drake boilers are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing \$2,600 - \$7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{35,36} The SCR system estimates for the CSU Drake boilers range from approximately \$5,000 - \$7,100, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 18, Table 20, and Table 22 illustrate resultant NO_x emissions for each technically feasible control option. Table 19, Table 21, and Table 23 show the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for tons of NO_x reduced per year, as noted in Table 2. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 18: Drake Unit 5 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	768	0.38	
Overfire air (OFA)	20	615	0.30	0.35
Ultra-low NOx burners (ULNBs)	26	569	0.28	0.32
ULNBs+OFA	28	553	0.27	0.31
Selective Non-Catalytic Reduction (SNCR)	30	538	0.26	0.30

³⁴ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

³⁵ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³⁶ Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

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ULNBs/SCR layered approach	81.5	142	0.070	0.080
Selective Catalytic Reduction (SCR)	81.5	142	0.070	0.080

Table 19: Drake Unit 5 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Overfire air (OFA)	154	\$141,844	\$923	\$923
Ultra-low NO _x burners (ULNBs)	200	\$147,000	\$736	\$112
ULNBs+OFA	215.2	\$288,844	\$1,342	\$9,230
Selective Non-Catalytic Reduction (SNCR)	231	\$1,011,324	\$4,387	\$47,011
ULNB/SCR layered approach	626	\$4,467,000	\$7,133	\$8,732
Selective Catalytic Reduction (SCR)	626	\$4,580,349	\$7,314	---

Table 20: Drake Unit 6 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,413	0.42	
Overfire air (OFA)	20	1,130	0.33	0.38
Selective Non-Catalytic Reduction (SNCR)	30	989	0.29	0.33
Ultra-low NO _x burners (ULNBs)	32	961	0.28	0.32
ULNBs+OFA	36	904	0.27	0.31
ULNBs/SCR layered approach	83.2	237	0.070	0.080
Selective Catalytic Reduction (SCR)	83.2	237	0.070	0.080

Table 21: Drake Unit 6 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Overfire air (OFA)	283	\$104,951	\$371	\$371
Selective Non-Catalytic Reduction (SNCR)	424	\$1,208,302	\$2,851	\$7,810
Ultra-low NO _x burners (ULNBs)	452	\$232,800	\$515	(\$34,525)
ULNBs+OFA	509	\$337,751	\$664	\$1,857

ULNBs/SCR layered approach	1,175	\$6,182,800	\$5,260	\$8,226
Selective Catalytic Reduction (SCR)	1,175	\$6,340,797	\$5,395	---

Table 22: Drake Unit 7 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	2,081	0.39	
Overfire air (OFA)	20	1,665	0.31	0.36
Ultra-low NO _x burners (ULNBs)	28	1,498	0.28	0.33
Selective Non-Catalytic Reduction (SNCR)	30	1,457	0.28	0.32
ULNBs+OFA	36	1,332	0.25	0.29
ULNBs/SCR layered approach	80.1	372	0.070	0.080
Selective Catalytic Reduction (SCR)	80.1	372	0.070	0.081

Table 23: Drake Unit 7 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Overfire air (OFA)	416	\$75,217	\$181	\$181
Ultra-low NO _x burners (ULNBs)	583	\$386,000	\$662	\$1,867
Selective Non-Catalytic Reduction (SNCR)	624	\$2,018,575	\$3,233	\$39,226
ULNBs+OFA	749	\$461,217	\$616	(\$12,473)
ULNBs/SCR layered approach	1,708	\$8,196,000	\$4,797	\$5,698
Selective Catalytic Reduction (SCR)	1,708	\$8,510,067	\$4,981	---

Energy and Non-Air Quality Impacts

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For example, CSU estimates that on Drake 7, the power consumption for a SCR system will be over 700 kW. These energy requirements are moderate (0.5% of Drake 7's gross output).

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on an aqueous ammonia reagent versus an ammonia reagent.

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 24 shows the number of days pre- and post-control. Table 25 depicts the visibility results (98th percentile impact and improvements) as

well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol³⁷, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO₂ and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 24: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour NOx rates	5	0.619	Rocky Mountain National Park	---		34	17		---
	6	0.827							
	7	0.710							
NOx Control Scenario	5	0.390		34	34	0	17	15	2
	6	0.390		34	31	3	17	14	3
	7	0.390		34	31	3	17	14	3
OFA	5	0.300*				n/a			
	6	0.330*				n/a			
	7	0.310*				n/a			
ULNBs	5	0.280*				n/a			
	6	0.282*				n/a			
	7	0.283*				n/a			
ULNBs+OFA	5	0.272*				n/a			
	6	0.266*				n/a			

³⁷ Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

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	7	0.251*		n/a					
SNCR	5	0.265*		n/a					
	6	0.291*		n/a					
	7	0.275*		n/a					
NOx Control Scenario	5	0.234		34	34	0	17	14	3
	6	0.234		34	31	3	17	14	3
	7	0.234		34	28	6	17	14	3
SCR	5	0.070		34	32	2	17	14	3
	6	0.070		34	27	7	17	14	3
	7	0.070		34	26	8	17	13	4
Combo	5	0.070		34	1	33	17	0	17
	6	0.070							
	7	0.070							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “CSU Drake BART Modeling Summary” for more details.

Table 25: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hour NOx rates	5	0.619	1.84	---	---	---
	6	0.827				
	7	0.710				
NOx Control Scenario	5	0.390	1.79	0.05	3%	n/a
	6	0.390	1.68	0.16	9%	n/a
	7	0.390	1.66	0.18	10%	n/a
OFA	5	0.300*	1.76	0.08	4%	\$1,970,053
	6	0.330*	1.66	0.18	10%	\$583,061
	7	0.310*	1.61	0.22	12%	\$335,791
ULNB	5	0.280*	1.76	0.08	4%	\$1,934,212
	6	0.282*	1.64	0.197	11%	\$1,181,727
	7	0.283*	1.60	0.24	13%	\$1,615,062
SNCR	5	0.265*	1.76	0.08	4%	\$12,641,549
	6	0.291*	1.64	0.19	11%	\$6,228,362
	7	0.275*	1.59	0.24	13%	\$8,272,850
ULNBs+OFA	5	0.272*	1.76	0.08	4%	\$3,703,128
	6	0.266*	1.63	0.20	11%	\$1,663,798

NOx Control Scenario	7	0.251*	1.58	0.26	14%	\$1,794,618
	5	0.234	1.75	0.24	5%	n/a
	6	0.234	1.62	0.24	12%	n/a
	7	0.234	1.57	0.24	15%	n/a
SCR	5	0.070	1.71	0.12	7%	\$36,024,194
	6	0.070	1.56	0.27	15%	\$22,647,619
	7	0.070	1.47	0.37	20%	\$22,091,644
Combo	5	0.070	0.25	1.59	86%	n/a
	6	0.070				
	7	0.070				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “CSU Drake BART Modeling Summary” for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Units 5, 6, and 7 is the following NO_x emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling hour average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling hour average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NO_x burners (including over-fire air).

- Unit 5: \$1,342 per ton NO_x removed
- Unit 6: \$664 per ton NO_x removed
- Unit 7: 616 per ton NO_x removed

The extremely low dollars per ton control costs, leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NO_x reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement does not meet the criteria guidance described in Chapter 6.4.3 of the Regional Haze SIP (*e.g.* less than 0.50 Δ_{adv})

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Public Service Company – Hayden Station**

I. Source Description

Owner/Operator: Public Service Company
 Source Type: Electric Utility Steam Generating Unit
 SCC (EGU): Unit 1: 10100222 Unit 2: 10100226
 Boiler Type: Pulverized Coal, Dry-Bottom, Front-Fired, firing coal (Unit 1 a)
 Pulverized Coal, Dry Bottom, Tangentially-Fired, firing coal (unit 2)

The facility is located four miles east of Hayden, Colorado at 13125 U.S. Highway 40 in Routt County. This facility consists of two (2) steam driven turbine/generator units (Units 1 and 2) and the associated equipment needed for generating electricity. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers. Only Units 1 and 2 are BART-eligible. Table 1 below lists the units at Public Service Company Hayden Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

Table 1: Hayden Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	July 1965	1976
Boiler Rating, MMBtu/Hr for coal	1,963	2,712
Electrical Power Rating, Gross Megawatts	190	275
Description	Riley-Stoker Pulverized Coal Front Fired Dry Bottom, firing coal with natural gas and No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Combustion Engineering Pulverized Coal Tangentially Fired Dry Bottom, firing coal with No. 2 fuel oil used for startup, shutdown, and/or flame stabilization.
Air Pollution Control Equipment	PM/PM ₁₀ - Reverse-Air Fabric Filter Baghouse NO _x – Low NO _x Burners with Over-Fire Air SO ₂ – Lime Spray Dryer	PM/PM ₁₀ – Reverse-Air Fabric Filter Baghouse NO _x – Low NO _x Burners with Over-Fire Air SO ₂ – Lime Spray Dryer

	All equipment commenced operation in December 1998	All equipment commenced operation in October – December 1999
Emissions Reduction (%)*	NO _x – 54.1% SO ₂ – 82.0% PM – 99.7% PM ₁₀ – 98.8%	NO _x – 33.3% SO ₂ – 79.6% PM – 99.7% PM ₁₀ – 98.9%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM₁₀. For NO_x and SO₂ estimates, CAMD data was used to calculate reductions. See “Hayden APCD Technical Analysis” for further details. Not based on actual testing.

Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to Division requests, PSCo submitted additional information on May 25 and July 14, 2010. The submittals are included as “PSCo BART Submittals”.

II. Emissions for Units 1 & 2

PSCo estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or “Baseline Emissions”, to be conservative, was the average of two previous years (2004, 2005) of emissions data in the September 14, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado’s Air Pollutant Emission Notices and EPA’s CAMD database. These emissions are summarized in Table 2.

Table 2: PSCo Hayden Units 1 & 2 Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)
NO _x	3,750	0.415	3,743	0.320
SO ₂	1,172	0.131	1,469	0.127
PM ₁₀	88.0	0.006***	109.3	0.004***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO₂ emissions.

***The PM₁₀ emission rate is determined from the latest Title V permit compliance stack test (June 2009). These values are as follows: Hayden Unit 1: 0.006 lb/MMBtu Hayden Unit 2: 0.004 lb/MMBtu

III. Units Evaluated for Control

PSCo notes that the Hayden boilers burn Colorado coal that primarily comes from two different mines in northwestern Colorado, the Twenty Mile Mine and the ColoWyo Mine. Coal characteristics are very similar from both of these mines. However, the ColoWyo coal is ranked as sub-bituminous while the Twenty Mile coal is ranked as bituminous (ASTM Method 388). However, PSCo performed an analysis using the Electric Power Research Institute (“EPRI”) NO_x/LOI Predictor software program (Version 2.1) to demonstrate that the more appropriate rating for ColoWyo coal is bituminous. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Hayden Station Coal Specifications (2004 – 2005)

Coal Mine/Region	Colowyo	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Bituminous
As Received Analysis		
H ₂ O (Moisture %)	16.8	9.8
Ash (%)	5.82	9.5
Sulfur (%)	0.36	0.49
Nitrogen (%)	1.33	1.65
Heating Value (HHV Btu/lb)	10,450	11,350
EPRI Model NO _x Prediction (lb/MMBtu)	0.46	0.39

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for PSCo Hayden BART-eligible sources¹

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Hayden Unit 1	22**	18.6	95	21.9
Hayden Unit 2	15**	18.6	95	21.9

*SO₂ and PM/PM₁₀ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 3.

**Assumed no low-NO_x burners.

IV. BART Evaluation of Units 1 and 2

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA’s BART Guidelines², electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not

¹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

² EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Hayden Units 1 and 2 if technically feasible. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system
- Additional equipment and maintenance: In the May 25, 2010 response to the Division, PSCo noted that Hayden Units 1 and 2 could potentially achieve a new reduced 30-day average emission rate limit of 0.13 lbs/MMBtu by conducting changes to the dry scrubber systems, so this option will be evaluated as part of possible semi-dry FGD upgrades.

The current Operating Permit limits are depicted in Table 5.

Table 5: Hayden Units 1 & 2 SO₂ Operating Permit Limits

	SO ₂ limits (lb/MMBtu)			Reduction (%) Required 30-day rolling
	3-hr rolling	30-day rolling	90-day rolling	
Units 1 & 2	1.2	0.160	0.130	82 (rounded)

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO₂ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the LSDs installed on Hayden Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Dry FGD Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants³. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

³ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

PSCo installed lime spray dryers (LSDs) in connection with baghouses on Hayden Units 1 and 2 1998 and 1999, respectively. PSCo notes that both of these dryers currently achieve greater than 80% removal, with actual annual averages of 0.13 lbs SO₂/MMBtu (each unit) in comparison with the permit limits⁴ depicted in Table 5. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits.

At the Division's request, PSCo submitted a SO₂ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the lime spray dryer systems at Hayden Station. Hayden's Babcock and Wilcox (B&W) lime spray dryers that use a single atomizer per scrubber module design that sprays a mixture of lime and recycled ash into the flue gas. This atomized mist then dries, reacts with SO₂ in the flue gas and is collected in the baghouse.

PSCo examined potential upgrades to the Hayden dry scrubbers, with the following results:

-Use of performance additives: The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO₂. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO₂ reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO₂ removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO₂ removal. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO₂ removal and therefore warrants no further consideration.

-Use of more reactive sorbent: All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve SO₂ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Hayden.

⁴ Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO₂. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO₂ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO₂ due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO₂ removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO₂ removal; there are no known acceptable reagents without side effects that would allow additional SO₂ removal in the dry scrubbing systems present at Hayden Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

-Increase the pulverization level of sorbent: The Hayden dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. There have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. PSCo's experience is that there is no SO₂ removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. Since PSCo already uses the best available grinding technologies, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO₂ removal.

-Engineering redesign of atomizer or slurry injection system: The Hayden dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO₂ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO₂ removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO₂ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO₂ removal level, although some have improved wear life and reduced maintenance costs.

However, PSCo provided to the Division upon additional request (July 14, 2010) additional information stating that an additional scrubber module (i.e. atomizer) would be required for each unit as well as additional spare parts and maintenance personnel in order to meet a lower emission limit. Therefore, this option is technically feasible.

-Additional equipment and maintenance: PSCo reviewed actual operating experience on Hayden along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO₂ control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO₂ emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO₂ by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall SO₂ control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

Based on a review of actual operating data and the factors noted above that affect short-term average SO₂ emission rates, PSCo believes Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit of 0.13 lbs/MMBtu as BART. This is currently the 90-day average emission limit for these units. In order to meet this lower limit on a 30-day average basis, the plant needs to purchase additional spare atomizer parts and increase annual operating and maintenance due to increased labor and reagent requirements.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected an annual average emission rate at 5% for Hayden to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by PSCo as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO₂ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to “Division RBLC Analysis” for more details.

Engineering redesign of atomizer or slurry injection system: At the Division’s request, PSCo sent cost information regarding the requirements for an additional scrubber module on July 14, 2010 in order to meet a SO₂ 30-day rolling emission limit of 0.08 lb/MMBtu, or 90% control efficiency (pre-control). This upgrade/redesign will result in control efficiencies of 41.7% and 40.1% beyond the current reductions shown in Table 1 on Units 1 and 2, respectively. Using this information, the Division calculated the resultant control effectiveness using the baseline and annual emissions for each unit. See “Hayden APCD Technical Analysis” for more information.

Dry FGD Upgrade – Additional equipment and maintenance: To evaluate the control effectiveness of tightening the 30-day rolling emission limits on Hayden Units 1 and 2, the Division used the annual baseline emissions, the average annual operating hours (2006 – 2008), and the daily heat input (MMBtu/day) to determine the emission rates at 0.13 lb/MMBtu and calculated the resultant control effectiveness and annual emissions for each unit.

Table 6 summarizes each available technology and technical feasibility for SO₂ control.

Table 6: Hayden Units 1 and 2 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Dry FGD Upgrades		
Use of performance additives	n/a	N
Use of more reactive sorbent	n/a	N
Increase pulverization level of sorbent	n/a	N
Engineering redesign of atomizer or slurry injection system	~40 – 42%	Y
Additional equipment and maintenance	~3 - 5%	Y

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Engineering redesign of atomizer or slurry injection system: The Division calculated cost estimates for an additional scrubber module – based on total capital and operating and maintenance costs provided in PSCo’s July 14, 2010 letter. PSCo stated that Hayden Station will need for an additional module on each unit as well as estimated spare parts and additional maintenance personnel (i.e. O&M costs). PSCo estimated capital costs for Unit 1 at \$37,000,000 and Unit 2 at \$43,000,000 and operating & maintenance costs at \$650,000 and \$750,000 for Units 1 and 2, respectively. These costs are determined based on meeting a more stringent 30-day rolling limit of 0.08 lb/MMBtu for each unit.

Dry FGD Upgrade – Additional equipment and maintenance: The Division calculated cost estimates for dry FGD upgrade – additional equipment and maintenance – based on total capital and operating and maintenance costs provided in PSCo’s May 25, 2010 letter. PSCo stated that Hayden Station will need spare atomizer parts at a cost of \$330,000 along with increased annual operating and maintenance costs of \$220,000 per year for reagent and labor to meet the more

stringent 30-day rolling SO₂ emission limit of 0.13 lbs/MMBtu. This cost analysis was conducted to demonstrate the impact of meeting the more stringent limit only. Table 7, Table 8, Table 9, and Table 10 show the SO₂ control cost per unit.

Table 7: Hayden Unit 1 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,172	0.131	
Dry FGD Upgrade – Additional Equipment and Maintenance	5.2%	1,111	0.124	0.130
Additional Scrubber Module	41.7%	684	0.076	0.080

Table 8: Hayden Unit 2 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,469	0.127	
Dry FGD Upgrade – Additional Equipment and Maintenance	2.7%	1,430	0.124	0.130
Additional Scrubber Module	40.1%	880	0.076	0.080

Table 9: Hayden Unit 1 SO₂ Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	61	\$141,150	\$2,317	\$2,317
Additional Scrubber Module	488	\$4,142,538	\$8,490	\$9,370

Table 10: Hayden Unit 2 SO₂ Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	39	\$141,150	\$3,626	\$3,626
Additional Scrubber Module	589	\$4,808,896	\$8,164	\$8,485

Energy and Non-Air Quality Impacts

There are no energy and non-air quality impacts related to tightening the emission limit for SO₂ beyond the acquisition of additional reagent. Thus, this factor does not influence the selection of controls.

Remaining Useful Life

PSCo asserts that the remaining useful life of Hayden Units 1 and 2 are each in excess of 20 year, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. Table 12 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol⁵, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

⁵ Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 11: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δ days	3-year totals		Δ days
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr SO ₂ rates	1	0.339	Rocky Mountain National Park	236	---	---	155	---	---
	2	0.402							
Dry FGD Upgrade	1	0.160*		n/a					
	2	0.160*		n/a					
Dry FGD Upgrade	1	0.130		236	228	8	155	147	8
	2	0.130		236	224	12	155	143	12
Additional Scrubber Module	1	0.100		236	228	8	155	146	9
	2	0.100		236	223	13	155	143	12
Additional Scrubber Module	1	0.070		236	228	8	155	146	9
	2	0.070		236	223	13	155	142	13
Combo	1	0.070							
	2	0.070		236	57	179	155	6	149

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden BART Modeling Summary” for more details.

Table 12: Visibility Results – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr SO ₂ rates	1	0.339	3.627	---	---	---
	2	0.402				
Dry FGD Upgrade	1	0.160*	3.540	0.09	2%	n/a
	2	0.160*	3.445	0.18	5%	n/a
Dry FGD Upgrade	1	0.130	3.525	0.10	3%	\$1,383,820
	2	0.130	3.422	0.21	6%	\$688,535
Additional Scrubber Module	1	0.100	3.505	0.12	3%	\$33,955,232
	2	0.100	3.395	0.23	6%	\$20,727,999
Additional Scrubber Module	1	0.070	3.485	0.14	4%	n/a
	2	0.070	3.367	0.26	7%	n/a

Combo	1	0.120	0.91	2.72	75%	n/a
	2	0.120				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden BART Modeling Summary” for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ BART the following SO₂ emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)
 Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSDs). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO₂ limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

B. Filterable Particulate Matter (PM₁₀)

Hayden Units 1 and 2 are each equipped with reverse-air fabric filter baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 13 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >99% control. The Title V permit limit is 0.03 lb/MMBtu. The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 13: Hayden Units 1 and 2 Stack Test Results (2009)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM ₁₀	0.006	0.004
PM ₁₀ Control efficiency	99.85%	99.91%

A Division review of EPA’s RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to “Division RBLC Analysis” for more details.

Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado’s SIP for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.V.8.c.ii(2).

The state has determined that the emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this control technology and emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA’s BART Guidelines, a full five-factor analysis for PM/PM₁₀ is not needed for Hayden Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

PSCo identified three options for NO_x control:

Low NO_x burners (next generation)

Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)®

Rich Reagent Injection (RRI)

Rotating overfire Air (ROFA)

Separated overfire Air (SOFA)

Low NO_x Burners (LNB)

LNB + SOFA

Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

Low NO_x burners (PSCo – LNB): PSCo evaluated low NO_x burner upgrades for Hayden Units 1 and 2, completing studies in July 2006. Units 1 and 2 currently have first-generation low NO_x burners and over-fire air systems. The combustion modifications include upgrades to these existing low NO_x burners rather than complete burner replacements. In addition, changes to the over-fire air systems were also needed to achieve further NO_x reductions on these units. LNB upgrades are technically feasible for Hayden Units 1 and 2.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent

reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Hayden Units 1 and 2.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Hayden, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative. PSCo economically evaluated a high-dust SCR arrangement. SCR is a technically feasible alternative for Hayden Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler⁶ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers⁷ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/ROFA®/SOFA/LNB+SOFA: Hayden Units 1 and 2 are already equipped with low NO_x burners with over-fire air (LNB+OFA) as part of a consent decree entered by the District Court on August 19, 1996, Civil Action 93-B-1749 and adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements," dated August 15, 1996. Table 1 illustrates that these systems achieve 49.5% and 43.3% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to

⁶ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

⁷ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load⁸. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+SOFA and is not expected to increase emissions reductions for Hayden Units 1 and 2. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+SOFA baseline for these units, ROFA® technology is not considered further in this analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu⁹. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals¹⁰, determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. The Division projected an annual average emission rate at 15% for Hayden to determine control efficiencies and annual reductions.

Low NO_x burners (PSCo – LNB): PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.24 lb/MMBtu respectively with upgraded low NO_x burner systems. The baselines from Table 2 show that Hayden Unit 1 baseline NO_x emissions are 0.415 lb/MMBtu and Unit 2 baseline NO_x is 0.320 lb/MMBtu. Therefore, the control effectiveness for upgraded low NO_x systems for Unit 1 is 37.1% and Unit 2 is 34.8%. As shown in Table 1, the current low-NO_x burners with overfire air systems achieve 54.1% and 31.3% control respectively. These upgrade control estimates are greater than EPA's AP-42 emission factor table, which estimate LNB with OFA as achieving 40 – 60% reduction.¹¹ In a recent AWMA study, wall-fired boilers burning sub-bituminous coal fitted with LNB+OFA system achieved NO_x reductions from 40 – 80.9% (similar to Hayden Unit 1). Tangential-fired boilers achieved NO_x reductions ranging from 11.3 – 74.4%.¹² With such wide control

⁸ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

⁹ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

¹⁰ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

¹¹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹² Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

efficiency ranges, the Division concludes that the 88.9% and 66.1% (pre-control) reductions estimated by PSCo are reasonable.

SNCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.21 lb/MMBtu respectively by installing SNCR on each boiler. Therefore, the control effectiveness for SNCR on Unit 1 is 37.1% and Unit 2 is 43.0%. These control effectiveness estimate is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers. Control effectiveness has been historically noted to be lower for wall fired boilers similar to Unit 1. Therefore, the Division concludes that the reductions estimated by PSCo are reasonable.

SCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.08 lb/MMBtu and 0.07 lb/MMBtu respectively by installing SCR on each boiler. Therefore, the control effectiveness for SCR on Unit 1 is 83.2% and Unit 2 is 81.0%. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.^{13,14}

Table 14 summarizes each available technology and technical feasibility for NO_x control.

Table 14: Hayden Units 1 and 2 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burner (LNB) Upgrade	~35 - 37%	Y
SNCR	20 – 50%	Y
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO _x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

¹³ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹⁴ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x burners (PSCo – LNB)/SNCR/SCR: PSCo completed engineering studies in July 2006 to evaluate the cost of combustion controls on Hayden Units 1 and 2. These cost estimates, in 2006 dollars, were based on vendor data and not on actual bids with performance guarantees. PSCo used the Coal Utility Environmental Cost Workbook (CUECost) to develop cost estimates for capital and annual costs, an EPA-approved methodology to estimate rough order-of-magnitude (ROM) cost estimates for air pollution control systems installed on coal-fired power plants ($\pm 30\%$).¹⁵ PSCo provided CUECost input files at the Division's request on April 20, 2010. PSCo used this program for LNB, SNCR, and SCR system estimates. The Division concurs that CUECost is an appropriate methodology for determining cost effectiveness regarding these control technologies.

LNB: In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 11.7% is consistent with an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.¹⁶ Therefore, the Division concludes that PSCo's estimates for LNBs are reasonable.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.¹⁷ The PSCo-estimated SNCR costs for operating expenses are 74% and 77% for Hayden Units 1 and 2 respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.¹⁸

The cost effectiveness for SNCR on Units 1 and 2 is about \$1,000 and \$1,200 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 2) achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced,

¹⁵ 2009, Yelverton, William H. "Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0. Prepared by: ARCADIS, 4915 Prospectus Drive, Suite F, Durham, NC 27713. Prepared for: U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC 27711.

¹⁶ Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

¹⁷ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

¹⁸ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

depending on initial capital costs and capacity factor.^{19,20} This same study estimate SNCR retrofits on wall fired boilers (similar to Unit 1) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing \$590 - \$1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. It should be noted that PSCo is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.²¹ PSCo's estimates are within this range. Therefore, the Division concludes that PSCo's cost estimates for SNCR are reasonable.

SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing \$2,600 - \$5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{22,23} In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 17% is higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.²⁴ However, PSCo's cost estimates are within the NESCAUM study ranges, so the Division concludes that PSCo's cost estimates for SCR are reasonable.

Table 15, Table 16, Table 17, and Table 18 depict controlled NO_x emissions and control cost comparisons.

Table 15: Hayden Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	3,750	0.415	
LNB*	37.1	2,359	0.261	0.300
SNCR*	37.1	2,359	0.261	0.300
SCR**	83.2	630	0.070	0.080

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

¹⁹ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁰ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²¹ EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.” <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

²² Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²³ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²⁴ Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 16: Hayden Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	3,743	0.320	
LNB*	34.8	2,441	0.209	0.240
SNCR*	43.0	2,134	0.183	0.210
SCR**	81.0	711	0.061	0.070

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 17: Hayden Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	1,391	\$572,010	\$411	\$411
SNCR	1,391	\$1,353,500	\$973	---
SCR	3,120	\$10,560,612	\$3,385	\$5,326

Table 18: Hayden Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	1,303	\$992,729	\$762	\$762
SNCR	1,610	\$1,893,258	\$1,176	\$2,934
SCR	3,032	\$12,321,491	\$4,064	\$7,331

Energy and Non-Air Quality Impacts

LNB: There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. These energy requirements are moderate.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

PSCo asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol²⁵, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO₂ and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART

²⁵ Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr NO _x rates	1	0.610	Mt. Zirkel Wilderness Area	236	---	---	155	---	---
	2	0.367							
NO _x Scenario	1	0.390		236	227	9	155	131	24
	2	0.280		236	230	6	155	144	11
NO _x Scenario	1	0.300		236	218	18	155	125	30
	2	0.210		236	226	10	155	137	18
LNB	1	0.261*		n/a					
	2	0.209*		n/a					
SNCR	1	0.261*		n/a					
	2	0.183*		n/a					
SCR	1	0.070		236	188	48	155	91	64
	2	0.070		236	213	23	155	116	39
Combo	1	0.070		236	57	179	155	6	149
	2	0.070							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden BART Modeling Summary” for more details.

Table 20: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Proposed Limit (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(deciviews)	(deciviews)	(%)	(\$/deciview)
Max 24-hr	1	0.610	3.63	---	---	---

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NO _x rates	2	0.367				
NO _x Scenario	1	0.390	3.13	0.50	14%	n/a
	2	0.280	3.42	0.20	6%	n/a
NO _x Scenario	1	0.300	3.02	0.60	17%	n/a
	2	0.210	3.23	0.40	11%	n/a
LNB	1	0.261*	2.94	0.69	19%	\$832,621
	2	0.209*	3.23	0.40	11%	\$2,500,576
SNCR	1	0.261*	2.94	0.69	19%	\$1,970,161
	2	0.183*	3.15	0.48	13%	\$3,969,094
SCR	1	0.070	2.51	1.12	31%	\$9,462,914
	2	0.070	2.77	0.85	24%	\$14,427,975
Combo	1	0.070	0.91	2.72	75%	n/a
	2	0.070				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden BART Modeling Summary” for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART is the following NO_x emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)
 Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan:

- Unit 1: \$3,385 per ton NO_x removed; 1.12 deciview of improvement
- Unit 2: \$4,064 per ton NO_x removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NO_x emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

APPENDIX D

Regional Haze State Implementation Plan

Technical Support for the Reasonable Progress Determinations

**Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Energy Nations, Golden, Colorado**

I. Source Description

Owner/Operator: Colorado Energy Nations (CENC) (formerly Trigen
Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 1 – Natural Gas Front-Fired
(SCC: 10200601 for natural gas)
Boiler 2 – Natural Gas Front-Fired
(SCC: 10200601 for natural gas)
Boiler 3 – Pulverized Coal Spreader Stoker
(SCC: 10200224)
Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired
(SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired
(SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek and US Highway 58 borders the northern side of the CENC site.

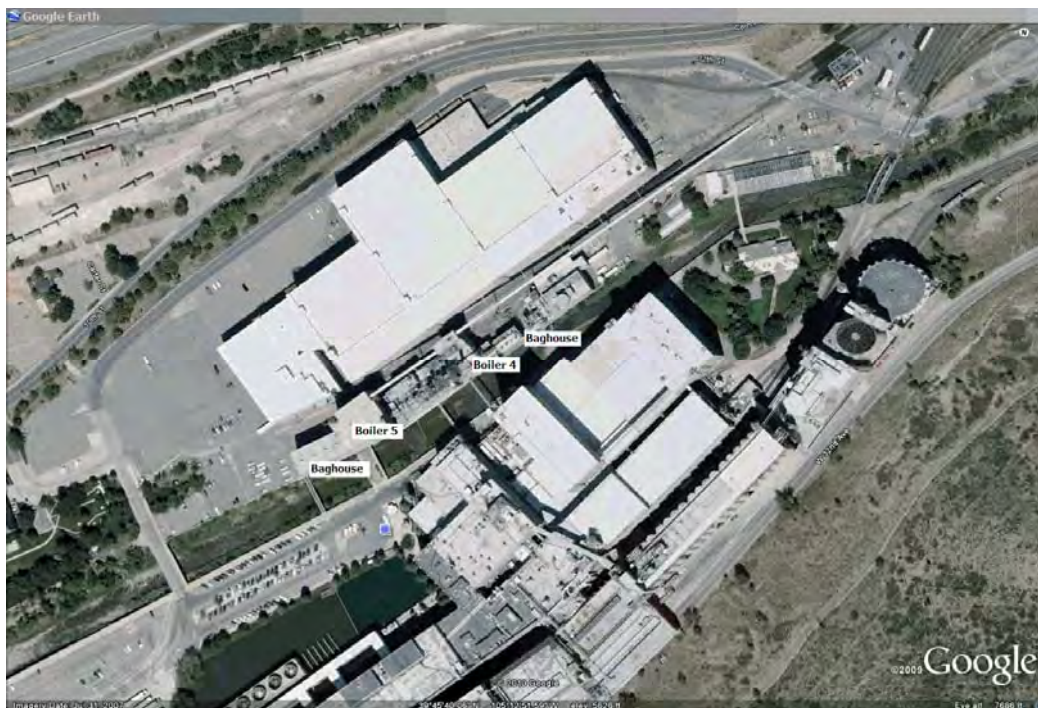


Figure 1: CENC facility Aerial Perspective

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operate in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM₁₀ by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the CENC facility, and information about similar facilities to determine RP for NO_x, SO₂, and PM₁₀. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is

located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control¹.”

These levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. CENC submitted a “Reasonable Progress Control Evaluation” on May 7, 2010 as well as additional relevant information on February 8, 2010. Table 1 depicts technical information for Boiler 3 at the CENC facility.

Table 1: CENC Boiler 3 RP-eligible Emission Controls and Reduction (%)

	Unit B003
Placed in Service	1962; updated to coal in 1981
Boiler Rating, MMBtu/Hr for coal	225
Electrical Power Rating, Gross Megawatts	24
Description	Combustion Engineering Model CE-VU40 225 MMBtu/hr (coal), traveling grate stoker, firing only coal for primary fuel and fuel oil/coal for a cold start
Air Pollution Control Equipment	Carter Day fabric filter baghouse with 4 compartments
Emissions Reduction (%)	NO _x – None SO ₂ – None PM/PM ₁₀ – 93+%

II. Source Emissions

CENC estimated that a realistic depiction of annual emissions for Boiler 3, or “Baseline Emissions” was the years 2006 – 2008. CENC determined that the maximum year within this scope was 2006, since it had the highest capacity factor and heat input.

Table 2 summarizes the NO_x, SO₂, and PM actual emissions averaged over the 2006 – 2008 timeframe for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado’s Air Pollutant Emission Notices

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

submitted by the facility and as applicable, EPA's CAMD Database (Boilers 4 and 5).

Table 2: Summary of 2006 - 2008 Averaged Emissions – CENC Facility

NO _x (tons/year)	SO ₂ (tons/year)	PM ₁₀ (tons/year)
1,512	2,433	38

Table 3: Summary of 2006 - 2008 Averaged Emissions by Unit - CENC Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
<i>Boiler #1 (288 MMBtu/hour – natural gas fired)</i>	<i>SO₂ (tons)</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>30.8</i>	<i>23.9</i>	<i>30.3</i>	<i>28.3</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>
	<i>PM₁₀ (tons)</i>	<i>0.8</i>	<i>0.7</i>	<i>0.8</i>	<i>0.7</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler # 2 (288 MMBtu/hour – natural gas fired)</i>	<i>SO₂ (tons)</i>	<i>0.1</i>	<i>0.0</i>	<i>0.1</i>	<i>0.1</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>32.4</i>	<i>10.4</i>	<i>27.6</i>	<i>23.5</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.03</i>	<i>0.01</i>	<i>0.02</i>	<i>0.02</i>
	<i>PM₁₀ (tons)</i>	<i>0.9</i>	<i>0.3</i>	<i>0.7</i>	<i>0.6</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler #3 (225 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>264</i>	<i>205</i>	<i>267</i>	<i>245</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.27</i>	<i>0.21</i>	<i>0.27</i>	<i>0.25</i>
	<i>NO_x (tons)</i>	<i>185</i>	<i>150</i>	<i>170</i>	<i>168</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.19</i>	<i>0.15</i>	<i>0.17</i>	<i>0.17</i>
	<i>PM₁₀ (tons)</i>	<i>2.3</i>	<i>1.9</i>	<i>2.1</i>	<i>2.1</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler #4 – (360 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>764</i>	<i>815</i>	<i>763</i>	<i>781</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.48</i>	<i>0.52</i>	<i>0.48</i>	<i>0.49</i>
	<i>NO_x (tons)</i>	<i>637</i>	<i>589</i>	<i>575</i>	<i>600</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.40</i>	<i>0.37</i>	<i>0.37</i>	<i>0.38</i>
	<i>PM₁₀ (tons)</i>	<i>10.9</i>	<i>10.0</i>	<i>10.4</i>	<i>10.4</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>
<i>Boiler #5 – (650 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>1,598</i>	<i>1,333</i>	<i>1,289</i>	<i>1,407</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.56</i>	<i>0.47</i>	<i>0.45</i>	<i>0.49</i>
	<i>NO_x (tons)</i>	<i>900</i>	<i>614</i>	<i>559</i>	<i>691</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.32</i>	<i>0.22</i>	<i>0.20</i>	<i>0.25</i>
	<i>PM₁₀ (tons)</i>	<i>21</i>	<i>17</i>	<i>16</i>	<i>18</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>
<i>P005 – Coal Unloading and Conveying</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.03</i>	<i>0.03</i>	<i>0.03</i>
<i>P007 – Boiler #5 Silos – coal conveyor to Unit 5 silos</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P008 – Ash Handling – 11, 12, 13 – general ash silo</i>	<i>PM₁₀ (tons)</i>	<i>5.57</i>	<i>5.57</i>	<i>5.38</i>	<i>5.51</i>
<i>P009 – Boiler #3 Silos – coal conveyor to Unit 5 silos</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P010 – Ash Handling – Boiler #4 & #5 fly ash</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>

<i>collection</i>					
<i>P011 – Ash Handling – Fly ash silo loadout</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P012 – Ash Handling – Fly ash silo bin vent</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P013 – Diesel Air Compressors – GM diesel engine for backup operation of air compressor</i>	<i>SO₂ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day NO_x rolling average is likely about 0.44 lbs/MMBtu for Boiler 4 and 0.29 lbs/MMBtu for Boiler 5).

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress. Boiler 3 currently has grandfathered status for State construction permits. This boiler is included in the current Title V permit, but does not currently have fuel usage or emission limitations for NO_x, PM, or SO₂. This boiler is subject to opacity requirements under Colorado Regulation No. 1, Section II.A.1 and a sulfur dioxide limit of 1.8 lbs/MMBtu when burning coal. Boiler 3 has a PM emission rate limit of 0.122 lbs/MMBtu and is controlled with a baghouse that was installed in the early 1980s. In addition to not utilizing a CEMS, a sophisticated automatic Data Acquisition System for control parameters, such as fuel usage, is not installed. The actual NO_x emissions is based on AP-42 factors applicable to the coal type (bituminous, sub-bituminous, etc.) and coal usage based on rail car / truck unloading records. This AP-42 factor has a B-rating and may be subject to change in the future. Unit 3 is a base-loaded boiler. It's load range varies from the low end (plant reliability—ready to respond in the event of a malfunction in Unit 4 or Unit 5), medium loads (increased customer steam loads) to high loads (i.e., during Unit 4 or Unit 5 overhauls). The load range varies within the month, and has patterns throughout the year. Therefore, the Division believes that a baseline period of 2000 – 2008 is warranted for CENC Boiler 3 due to the factors listed above. The baseline emissions for Boiler 3 are further detailed in Table 4

Table 4: CENC Unit 3 Detailed Baseline Emissions

Pollutant	Unit 3 (2000 – 2008)	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO _x	205	0.21
SO ₂	257	0.26
PM ₁₀	2	0.037***

*Using most recent three calendar years (Division APEN data).

**The Division calculated annual average rate (lb/MMBtu) from the most recent three calendar years, the maximum heat input and annual operating hours.

***The PM₁₀ emission rate is determined from the last Title V permit compliance stack test (August 24, 2007).

III. Units Evaluated for Control

As documented by CENC, this boiler fires low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 5.

Table 5: Coal Specifications (2006 – 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B003	12,541	0.42	8.38

Table 1 lists the units at Colorado Energy Nations Golden Facility that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for CENC Boilers

Emission Unit	Pollutant	Fuel
		Coal (bituminous) (lb/ton)
Boiler 3 ²	NO _x	11
	SO ₂	38 x %S = 16.0*
	PM/PM ₁₀	PM – 66 PM ₁₀ – 13.2

*%S = % of sulfur present in coal supply. For example, 38 x 0.42 = 16.0

**%A = % of ash present in coal supply. For example, 10 x 8.39 = 83.9

It is worth noting that although Boiler 3 was on-line the majority of the time, it ran at reduced capacity due to production requirements, demonstrated in Table 7.

Table 7: Boiler 3 Baseline Capacity Factor

Heat Input (HI) (MMBtu/year)		
Potential HI	1,971,000	B3 % Potential-HI
2006	874,569	44.37%
2007	711,157	36.08%
2008	805,320	40.86%
Average	797,015	40.44%

IV. Reasonable Progress Evaluation of Boiler 3

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CENC identified five SO₂ control options:

Flue gas desulfurization (FGD):

Lime or limestone-based (wet FGD)

² EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf>

Lime spray dry absorber (SDA or dry FGD)
Dry sorbent injection – Trona (DSI)
Fuel switching – different coal type
Fuel switching – natural gas

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants³. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a “foot print” area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also

³ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

⁴ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

bound the facility to the north and east. Table 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO₂, the design gas residence time in a SDA is approximately 10 seconds. For Boiler 3, a SDA vessel for each boiler, not including other associated equipment, would be approximately 27 feet in diameter by 47 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash from the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on Boiler 3.

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO₂ controls on Units 4 and 5. It can be reasonably assumed that this visit also applies to Unit 3. The Division noted:

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.



Figure 2: Aerial Zoom of CENC Facility

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, NO_x to SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boiler 3.

Fuel Switching – Different Coal Type: CENC asserts that the facility already utilizes low sulfur, high heating value bituminous coal from western Colorado. Typically, the coal contains only about 0.43 percent sulfur with a heating value of 12,100 Btu/lb and potential SO₂ emissions of 0.73 lb/MMBtu. The sulfur content of CENC's Colorado coal rivals the low sulfur properties of Powder River Basin (PRB) coal from Wyoming, and therefore, it represents the lowest sulfur coal available. Any shift from the purchase of local Colorado coal would have an adverse effect on Colorado mining and transportation industries.

Additionally, CENC notes that PRB coal is extremely dusty to handle, being much more friable than the Colorado coal presently used) and it generates dust through weathering much more quickly than bituminous coal. PRB coal also is subject to spontaneous combustion in and around material handling systems and silos. The generation of fugitive dust and periodic spontaneous combustion is a tremendous issue at a site such as a Coors Brewery, which precludes conversion to PRB coal. Therefore, a change in coal supply is not a feasible RP control option.

Fuel Switching – Natural gas: Natural gas offers some operating and maintenance advantages. The use of natural gas would eliminate coal handling and baghouse operating and maintenance labor as well as ash handling and disposal. Natural gas fuel switching is a feasible option for CENC Boiler 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boiler 3 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers.

DSI: CENC asserts that the maximum SO₂ removal rate that can be achieved to be 65% SO₂ removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals⁵ and to be conservative since this technology is relatively novel.

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO₂ emissions by almost 100% from each unit using EPA’s AP-42 emission factors⁶ and concurs with CENC’s submittal.

Table 8 summarizes each available technology options and technical feasibility for SO₂ control on CENC Boiler 3.

Table 8: CENC Boiler 3 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90% ⁷	Y
Dry FGD	70 – 90% (CENC)	N
DSI (Trona)	≤65% (CENC)	Y
Fuel switching – different coal type	minimal (CENC)	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

CENC submitted cost estimates for DSI and natural gas fuel switching for Boiler 3 on May 7, 2010.

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.

⁵ Colorado Springs Utilities, 2010. “RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5.” Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

⁶ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

⁷ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. . DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO₂ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO₂ collected. Detailed capital and annual cost data are presented in "CENC RP APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI.

Table 9: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Ratio (\$/kW)
Colorado Energy Nations – Boiler 3	24	\$1,340,661	\$9,114	\$55.86
Colorado Energy Nations – Boiler 4	35	\$1,766,000	\$3,774	\$50.46
Colorado Springs Utilities – Drake Unit 5	51	\$1,746,172	\$2,293	\$34.33
Colorado Energy Nations – Boiler 5	65	\$2,094,000	\$2,485	\$32.22
Colorado Springs Utilities – Drake Unit 6	85	\$2,910,287	\$1,741	\$34.24

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.⁸ CENC Boiler 3 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

Fuel Switching – Natural Gas: The Division used EPA's Cost Control Manual⁹ to estimate annual operating costs, of approximately \$25,000 per ton of SO₂

⁸ ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

⁹ EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

removed annually for Boiler 3 at the CENC facility.¹⁰ However, it should be noted that natural gas prices vary significantly; the Division used 2008 commercial natural gas prices reported by the U.S. Energy Information Administration¹¹ to determine natural gas costs. Therefore, the Division concurs that the natural gas estimates submitted by CENC on May 7, 2010 to be reasonable.

In the February 8, 2010 submittal, CENC notes that the fuel is the largest steam production cost incurred by CENC, and stresses the variability in natural gas prices. CENC also emphasized the added negative Colorado economic impact in that CENC coal is purchased from Colorado mines, which may be offset by the natural gas purchases also from Colorado-based corporations. The use of natural gas would eliminate pulverizer and baghouse operating and maintenance costs as well as ash handling and disposal costs. Other boiler maintenance costs would be reduced if coal was not burned.

Table 10: CENC Unit 3 Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	257	0.260	0.273
DSI - Trona	60	103	0.104	0.109
Fuel Switching - Natural Gas	100	0	0.000	0.000

Table 11: CENC Unit 3 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
DSI - Trona	154	\$1,340,661	\$8,709	\$57
Fuel Switching - Natural Gas	257	\$1,428,911	\$5,569	-\$31

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control

¹⁰ Colorado Air Pollution Control Division Technical Analysis – CENC RP APCD Technical Analysis, 2010.

¹¹ U.S. Energy Information Administration, 2010.
http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dc_u_nus_a.htm

options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or “first in time - first in right,” and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado’s domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO₂ control technology consideration on commercially available once-through dry FGD controls, specifically, “lime spray dryers” (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO₂ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO₂ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO₂ emission reduction benefits (tons of SO₂ reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when applied to this small boiler at the CENC facility (Boiler 3).

DSI: CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,¹² which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.08 Δ dv for DSI applied to Boiler 4 (360 MMBtu/hr). DSI controls for Boiler 4 would reduce SO₂ emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce SO₂ emissions by about 147 tons per year. Fuel switching to natural gas would reduce SO₂ emissions by an estimated 245 tons annually. Consequently, it is reasonable to infer, based on scaling, that either control applied to Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δ dv.

¹² Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cetc/resources/pdfs/lifac/LIFAC_PPA.pdf

Table 12: CENC Boiler 4 SO₂ Modeling Results

SO ₂ Control Method	CENC - Boiler 4		
	Emission Reduction (tpy)	SO ₂ Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δv)
Daily Maximum (3-yr)	---	0.90	---
DSI - Trona	268	0.26	0.08

Determination

Table 13 illustrates fuel analysis from 2000 – 2010. The Division believes a 20% contingency factor is warranted for CENC Boiler 3 due to the factors listed on page 5. Based on Table 13, the maximum SO₂ emissions from the past decade (2000 – 2010) is 0.99 lb/MMBtu. With the uncertainty factor, the Division believes that a 1.2 lb/MMBtu is appropriate for RP.

Table 13: CENC Boiler 3 Coal Supply SO₂ Limit Support

	2000-2006	2006-2008	2009-2010
Minimum Btu/lb	11,068	11,221	11,444
Maximum % Sulfur	0.55	0.55	0.57
<i>Theoretical lb/MMBtu...</i>			
Maximum B3 Conversion Sulfur to SO ₂ (using fuel analysis)	0.99	0.98	0.99

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ RP is the following SO₂ emission rate:

CENC Boiler 3: 1.2 lb/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

b. Filterable Particulate Matter (PM and PM₁₀)

CENC Boiler 3 is equipped with fabric filter baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Condition 2.2 requires Boiler 3 to comply with State Regulation No. 1 where the PM/PM₁₀ emission limit is calculated from the equation $PE = 0.5(FI)^{-0.26}$, where PE= Particulate Emissions in lbs/MMBtu and FI = Fuel input in million Btu per hour. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 14 shows the most recent stack test data (August 24, 2007). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >90% control.

Table 14: CENC 2007 Stack Test Results

Pollutant	Boiler 3 (lb/MMBtu)
Filterable PM ₁₀	0.037
PM ₁₀ Control efficiency	93.0%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

This boiler is subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.¹³ As currently proposed, the boiler will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).¹⁴

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of

¹³ EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

¹⁴ EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible (less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The state has determined that an emissions limits of 0.07 lb/MMBtu (PM/PM₁₀ represents the most stringent control option. The unit is exceeding a PM control efficiency of 90%, and the control technology and emission limit is RP for PM/PM₁₀. The state assumes that the RP emission limit can be achieved through the operation of the existing fabric filter baghouse.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CENC, using a similar unit's NO_x analysis¹⁵, identified eight potential NO_x control options:

- Flue Gas Recirculation (FGR)
- Low-temperature Oxidation System (LoTOx)
- Selective Non-Catalytic reduction (SNCR)
- Rotating Over-Fire Air w/ Rotamix (ROFA)
- Fuel switching – different fuel type (natural gas)
- Regenerative Selective Catalytic Reduction (RSCR)
- High Temperature Selective Catalytic Reduction (HT SCR)
- Low Temperature Selective Catalytic Reduction (LT SCR)

The Division also identified and examined the following additional control option for this unit:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

Flue Gas Recirculation (FGR): FGR technology extracts up to 20 to 30% of the flue gas from downstream of the economizer, air heater, or particulate control equipment, and is mixed into the combustion inlet air duct. The amount of FGR

¹⁵ "Black Hills Clark Station NO_x Reduction Feasibility Study" BH Clark Station Unit 1. Prepared by CH2MHill. December 2009.

that is achievable is determined by a boiler's operating characteristics and the ability to mix with primary air to allow for good fuel bed combustion stability. Flue gas recirculation is considered technically feasible for CENC Boiler 3.

LoTOx System: The LoTox system has the potential of significant NO_x reduction; however, the process requires operation in conjunction with a wet scrubber. CENC does not currently have a wet scrubber in service, has a limited footprint in which to locate a wet scrubber, and the Division has determined that wet scrubbers are not being considered for this facility due to non-air and energy impacts. Therefore, the LoTOx alternative is not considered due to the determination regarding wet scrubbers.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SNCR is considered a technically feasible alternative for CENC Boiler 3.

ROFA: Nalco Mobotec markets ROFA as an improved second generation OFA system. ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. Nalco Mobotec offers the ROFA system as a stand-alone installation, or with the Rotamix feature. Rotamix is Nalco Mobotec's version of SNCR technology, and ammonia is injected into the ROFA airstream. ROFA is considered technically feasible for CENC Boiler 3.

Fuel switching – different fuel type (natural gas): Natural gas reburning technology is a staged fuel approach using an expanded volume of the furnace to control NO_x production, rather than only within the flame envelope, also referred to as Methane de-NO_x. The primary solid fuel combustion delivery and boiler location remains the same, and for the case of CENC Boiler 3 this is currently assumed to occur on the traveling fuel grate. The secondary fuel introduction point is after the primary fuel burn zone, in a fuel-rich reaction zone (the reburn zone). While other fuels may be used in the reburning zone, natural gas is most common and NO_x reductions of 30-70% may be feasible. Higher removals are associated with longer boiler residence times. Therefore, 50% was used for the analysis due to the relatively short boiler at CENC (similar to Black Hills Clark Station Unit 1). Natural gas fuel switching is considered a technically feasible alternative for CENC Boiler 3.

RSCR/HT SCR/LT SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

CENC estimated that a retrofit SCR system on Boiler 3 could achieve 0.024 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. CENC evaluated three types of SCR for this analysis – regenerative SCR, high-temperature SCR, and low-temperature SCR. These three different options were evaluated because of the potential variable inlet temperature on a spreader stoker boiler such as Unit 3. Regenerative SCR notably may not achieve the same reductions as the other two SCR options, but regardless was evaluated. All three SCR options – RSCR, HTSCR, and LTSCR – are considered technically feasible for CENC Boiler 3.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler¹⁶ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers¹⁷ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boiler 3.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu¹⁸. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

¹⁶ Powerspan ECO®: Overview and Advantages, 2000 – 2010.

http://www.powerspan.com/ECO_overview.aspx

¹⁷ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009.

<http://www.ftek.com/apcRRI.php>

¹⁸ Coal Tech. Corp, 2002. “Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers.”

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,¹⁹ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boiler 3 to determine control efficiencies and annual reductions.

Flue Gas Recirculation (FGR): CENC estimated a 20% NO_x reduction. Flue gas recirculation is considered an operational modification, since fuel is rearranged in the main combustion zone. EPA's AP-42 emission factor tables estimate operational modifications to reduce NO_x 10 – 20%.²⁰ It should be noted the baseline NO_x emission rate (0.17 lb/MMBtu) is much lower than other spreader stoker boilers examined in many control case studies.²¹ The Division considers this level of control optimistic and concurs with CENC's control efficiency estimates for FGR.

SNCR: CENC noted in the May 6, 2010 submittal that the similar unit was assumed to achieve 40% control for SNCR. However, CENC determined that 30% control was a more realistic estimate. EPA's SNCR Air Pollution Control Technology Fact Sheet states that SNCR achieves 30 – 50% control, which concurs with the Division's experience. The Division determined in CENC's BART analysis that an appropriate NO_x reduction estimate is 30%; therefore, the Division concurs with CENC's control efficiency estimate.

ROFA: A recent AWMA study noted that ROFA achieves from 45 – 60% NO_x reduction depending on temperature and distribution of combustion products.²² CENC estimated a reduction of 57.1% based on a vendor guarantee for a similar unit. This results in a resultant NO_x emission rate of 0.07 lb/MMBtu. In the Division's experience, this emission rate may not be realistically achievable and will require more study if applicable.

Fuel switching – different fuel type (natural gas): CENC estimates 50% NO_x reduction by converting fuel to natural gas. This is equal to about 0.09 lb/MMBtu, which is consistent with EPA's AP-42 emission factor tables for a

¹⁹ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

²⁰ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.
<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²¹ EPA, Office of Air and Radiation. "Alternative Control Technique Document – NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers." Emission Standards Division.
<http://www.epa.gov/ttn/cat1/dir1/icboiler.pdf>

²² Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

large wall-fired boiler controlled with flue gas recirculation (0.098 lb/MMBtu).²³ Therefore, the Division concurs with CENC's control efficiency estimate.

RSCR/HT SCR/LT SCR: CENC estimates 74.5% NO_x control for RSCR and 85.7% for HTSCR and LTSCR. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.^{24,25} RSCR will not achieve the same control efficiencies as HTSCR and/or LTSCR due to the heat input being required through burner arrangement located between two canisters and can be applied to relatively cold flue gas temperatures seen after particulate control equipment. The Division notes that these control efficiencies, due to the low baseline NO_x emission rate, result in extreme emission rates (0.02 – 0.04 lb/MMBtu) and may not be realistically achievable, but concurs with CENC's current estimate for purposes of this RP evaluation.

Table 15: CENC Boiler 3 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners (LNB)	n/a	N – coal stoker boiler
Flue Gas Recirculation (FGR)	~20%	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
Rotating Overfire Air (ROFA)	45-60%	Y
Fuel switching – natural gas	~50%	Y
Selective catalytic reduction options (RSCR, HTSCR, LTSCR)	~75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

FGR: The costs of flue gas recirculation for stoker boilers are not well documented. This type of modification is considered a pre-combustion boiler modification. This modification should be more cost-effective than other options,

²³ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf>

²⁴ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²⁵ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

considering that either a new FGR fan will have to be installed or that the existing forced draft (FD) fan may be used to inject the flue gas into the combustion air. The Division considers the annualized cost of approximately \$280,000 for FGR to be reasonable for this small boiler.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of CENC Boiler 3.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.²⁶ The CENC-estimated SNCR costs for operating expenses is about 77% for Boiler 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.²⁷

The Division calculates cost effectiveness (using CENC cost estimates) for SNCR on Boiler 3 to be about \$10,150 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{28,29} EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.³⁰ CENC's estimates are greater than these ranges due to the small size of the boiler, the difficulty of the retrofit, and the different boiler configuration. There is a lack of information regarding the application of SNCR to spreader stoker boiler. Therefore, the Division concludes that CENC's cost estimates for SNCR are reasonable.

ROFA: The Division notes lack of information regarding ROFA cost estimates, especially applied to spreader stoker boilers. Therefore, the Division notes that CENC's estimated ROFA annualized costs are similar to SNCR, which is a

²⁶ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

²⁷ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet."
<http://www.epa.gov/ttn/catc/dir1/fsncr.pdf>

²⁸ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."
<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁹ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

³⁰ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet."
<http://www.epa.gov/ttn/catc/dir1/fsncr.pdf>

comparable control technology in terms of achievable reductions and concludes that CENC's cost estimates for ROFA are reasonable.

RSCR/HTSCR/LTSCR: Using CENC estimates, the Division calculates that the three SCR options range from \$15,650 - \$22,300 per ton. Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing \$2,600 - \$5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{31,32} CENC's cost estimates are much higher than this range, but the small size of the boiler, the difficulty of the retrofit, and the boiler configuration, the Division concludes that CENC's cost estimates for SCR are reasonable.

Table 16: CENC Boiler 3 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	180	0.25		56	65
Flue Gas Recirculation	20.0	144	0.15	0.17	41	47
SNCR	30.0	144	0.13	0.15	33	38
Fuel Switching - NG	34.8	118	0.12	0.14	29	33
ROFA w/ Rotamix	57.1	77	0.08	0.09	18	20
Regenerative SCR	74.5	46	0.05	0.05	11	12
High Temperature SCR	85.7	26	0.03	0.03	6	7
Low Temperature SCR	85.7	26	0.03	0.03	6	7

³¹ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³² Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 17: CENC Boiler 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Flue Gas Recirculation	33.7	\$278,358	\$7,716	\$214
SNCR	50.6	\$513,197	\$9,484	\$98
Fuel Switching - NG	58.7	\$1,428,911	\$22,763	\$1,534
ROFA w/ Rotamix	96.3	\$978,065	\$9,496	-\$330
Regenerative SCR	125.6	\$1,965,929	\$14,629	\$164
High Temperature SCR	144.5	\$2,772,286	\$17,933	\$164
Low Temperature SCR	144.5	\$3,222,223	\$20,844	---

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

FGR: Installation of a FGR system is not expected to impact the boiler efficiency or forced draft fan power usage significantly. Thus, this factor does not influence the selection of this control.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ROFA w/ Rotamix: The ROFA system requires installation and operation of the ROFA fans on this boiler, with a 125 hp fans being anticipated based on a similar boiler analysis. The Rota system alone will have a modest increase in power consumption. This system may result in higher levels of carbon in the fly ash due to incomplete combustion. Rotamix may impact any potential salability of fly ash due to ammonia levels. However, the Division is not currently aware of CENC selling fly ash.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to “CENC BART Submittals” for more information.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.12 Δv for LNB+SOFA+SNCR applied to Boiler 4 (360 MMBtu/hr). LNB+SOFA+SNCR controls for Boiler 4 would reduce NO_x emissions by approximately 368 tons per year. SCR controls for Boiler 3 would reduce NO_x emissions by about 145 tons per year. Consequently, it is reasonable to infer that either control applied to

Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δ dv.

Table 18: CENC Boiler 4 NO_x Modeling Results

NO _x Control Method	CENC - Boiler 4		
	Emission Reduction (tpy)	NO _x Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
Daily Maximum (3-yr)	---	0.67	
LNB	60	0.45	0.05
SNCR	180	0.35	0.07
LNB + SOFA	210	0.32	0.08
LNB + SOFA + SNCR	368	0.19	0.12

Determination

Based on review of historical actual load characteristics of this boiler, the Division proposes an annual NO_x ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor (similar to SO₂) due to the reasons listed on page 5.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NO_x RP for Boiler 3 is following NO_x emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with minimal visibility improvement ($\ll$ 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan, and thus not reasonable.

V. Reasonable Progress Evaluation of Boiler 4 and Boiler 5

Boiler 4 and Boiler 5 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Boilers 4 and 5 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO₂, and PM/PM₁₀ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO₂, or PM/PM₁₀ for Boiler 4 and Boiler 5 at the CENC facility.

COMBUSTION TURBINE POINT SOURCE CATEGORY 4-FACTOR ANALYSIS

I. Source Description

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the State's air emissions inventory. Typical emissions for this source type may be significant for NO_x, but pipeline quality natural gas is inherently clean and low-emitting for SO₂ and PM₁₀ emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

Control strategies for this source category are:

NO_x – Steam or water injection, advanced dry low NO_x combustion system, and selective catalytic reduction (SCR)

Cumulatively, this emissions source category is projected to be a minimal single category of Colorado point sources with a total of 56 turbines. Of this total, turbines located as single sources at Reasonable Progress facilities are 18. Total state-wide NO_x emissions (2007 inventory) are approximately 284,037 tons/year. This source category is about 0.7% of total statewide emissions; therefore, the Division considers this source category to be nominal. Regardless, the Division evaluated all combustion turbines, regardless of fuel type, at Reasonable Progress facilities. The majority of combustion turbines (assumed 17 out of 18 based on inventory limitations) are natural-gas fired.

II. Source Emissions

Pollutant	Total 2006 – 2008 Averaged Annual Emissions (tpy)	Total RP Turbine 2006 – 2008 Averaged Annual Emissions (tpy)	RP Turbine Emissions compared to total state-wide turbine emissions (%)
NO ₂	2,003	473	24%

The Division analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are 5 Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe

Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two emit over federal significance levels as depicted below.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of NO_x equal to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for SO₂, NO_x and PM₁₀ to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines “emissions unit” as “any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term “unit” for purposes of Title IV (acid deposition control) of the federal act, or of the term “source” for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3.¹” These *de minimis* levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

Facility – Turbine	Total 2006 – 2008 Averaged NOx Annual Emissions (tpy)	Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy)	Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy)	Greater than <i>de minimis</i> levels?
Valmont – Turbine #6	12.6	0.4	0.1	No
Valmont – Turbine #7	27.4	0.2	2.8	No
Valmont – Turbine #8	1.5	0.0	0.1	No
Arapahoe – Turbine #5	25.5	0.4	5.0	No
Arapahoe – Turbine #6	15.3	0.4	5.0	No
Arapahoe – Turbine	4.1	0.2	3.7	No
Nixon – Turbine #2	0.7	0.0	0.2	No
Nixon – Turbine #3	1.2	0.0	0.3	No
Nixon – Front Range Power	159.6	2.9	4.9	Yes – NOx only

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

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Plant – Turbine #1				
Nixon – Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only
Rawhide Turbine A	2.5	0.1	0.5	No
Rawhide Turbine B	4.0	0.1	0.8	No
Rawhide Turbine C	2.7	0.1	0.5	No
Rawhide Turbine D	2.9	0.1	0.5	No
Pawnee – Turbine #1	25.4	0.3	3.3	No
Pawnee – Turbine #2	25.0	0.2	2.7	No

Therefore, for the purposes of this RP planning period, the Division will evaluate the Nixon – Front Range Power Plant – Turbines #1 and #2 as they are the two combustion turbines emitting over *de minimis* levels.

III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Four technologies have been identified to lower emissions from combustion turbines:

1. Wet controls using steam or water injection to reduce combustion temperatures for NOx control
2. Dry controls using advanced combustor design to suppress NOx formation and/or promote CO burnout
3. Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

Technology #2: This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 “Compilation of Air Pollutant Emission Factors.” The following is from the 5th Edition, Volume 1, Chapter 1, Section 3.1.4.1: “Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.”

Technology #3: This technology was identified by the EPA and is documented in the AP-42 “Compilation of Air Pollutant Emission Factors.” The following is from the 5th

Edition, Volume 1, Chapter 1, Section 3.1.4.2: "Since thermal NO_x is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_x emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_x formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_x emissions associated with the high temperature pilot flame are insignificant. Low NO_x emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H₂, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_x generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_x formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NO_x (DLN), Dry-Low Emissions (DLE), or SoLoNO_x."

Technology #4: This technology (adding SNCR or SCR) involves adding control equipment and reagent to treat turbine exhaust.

Step 2: Eliminate Technically Infeasible Options

Technology #1: This technology is technically feasible.

Technology #2: This technology is technically feasible.

Technology #3: This technology is technically feasible and is already installed at the Nixon – Front Range Power Plant combustion turbines.

Technology #4: This technology is technically feasible, although a Division of the EPA's RBLC database revealed SCR is the predominant post-combustion control technology for combustion turbines and did not find any examples of SNCR post-combustion technology applied to combustion turbines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Technology #1: Since this control technology is specific fuel type usage, control efficiency are not applicable.

Technology #2: EPA's AP-42 factor database cites this technology as achieving control efficiencies of 60% or greater. However, this technology will not be evaluated in this analysis further since the dry low-NO_x combustion systems already installed on the turbines at the Front Range Power Plant achieve greater than 85% control, which is greater than the 60% estimate achievable by wet controls.

Technology #3: The Division calculated that the controlled-uncontrolled ratio for advanced dry-low NO_x combustions using EPA's AP-42 emission factors is approximately 70% and may be greater in site-specific cases. The combustion turbines at the Nixon – Front Range Power Plant were installed with these systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NO_x reductions (calculated using the 2006 – 2008 RP baseline period), respectively.

Technology #4: EPA's AP-42 emission factor description indicates that a SCR in good working order can achieve removal efficiencies ranging from 65 – 90 percent from the NO_x exhaust stream. AP-42 is silent on control efficiencies regarding SNCR. During a research review, the Division could not find any instances of a commercial-scale SNCR applied at a natural-gas fired combustion turbine. Therefore, SNCR will not be considered further in this analysis.

Step 4: Evaluate Impacts and Document Results

The Division reasons that SCR requires significant capital expenditures and will result in minimal additional NO_x reductions, if any. Regardless, the Division analyzed additional achievable NO_x reductions if SCR was installed at these two turbines. Applying SCR at 90% to both turbines would result in about 275 additional tons of NO_x reduced annually. Using another Colorado SCR analysis from the same utility (Colorado Springs Utilities), the Division estimates that annualized costs for installing SCR to both turbines will be approximately \$8 million each, resulting in about \$57,000 - \$62,000 per ton of NO_x reduced annually.

The time necessary for compliance will depend on the type of control implemented. Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the SCR control option. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

There are no energy or non-air quality impacts for fuel usage of pipeline quality natural gas or for advanced dry low-NO_x combustion systems. The energy and non-air quality impacts of SCR and SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Step 5: Select Reasonable Progress Control

The Division determines that any potential reductions from this source category are minimal, if any. Pipeline quality natural gas is inherently clean for SO₂ and PM₁₀. For NO_x, the majority of combustion turbines already apply advanced dry-low NO_x combustion systems, especially the larger turbines.

Based on its consideration of the four factors summarized herein, the state has determined that NO_x RP for combustion turbines is existing controls and emission limits. Though other controls achieve better emission reductions, the expense of these options coupled with predicted minimal visibility improvement were determined to be excessive.

**Reasonable Progress Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Unit 3**

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100202
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2) and one front-fired (Unit 3)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Unit 3, rated at 4,600 MMBtu/hour (net 408 MW) was placed in service in 1984.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO₂) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO₂ and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area.

For this analysis, the Division also relied on the existing Construction permit, historical information regarding Craig Station, and information about similar facilities to determine RP for NO_x, SO₂, and PM₁₀. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same. Units 1 and 2 are considered BART-eligible, being industrial boilers

with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines “unit” as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as “any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control¹.”

These levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010. **Error! Reference source not found.** depicts technical information for Unit 3 at Craig Station.

Table 1: Craig Unit 3 Technical Information

	Unit 3
Placed in Service	1984
Gross Boiler Rating, MMBtu/Hr for coal	4,600
Electrical Power Rating, Net Megawatts	408
Description	Babcock & Wilcox coal, dry bottom boiler - Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization
Air Pollution Control Equipment	PM/PM ₁₀ – Pulse Jet Fabric Filter Baghouse (1984 – upgraded between 2007 and 2009) NO _x – Low NO _x Burners with Over-Fire Air (upgraded between 2007 and 2009) SO ₂ – Dry Limestone FGD (1984 – upgraded between 2007 and 2009) Existing turbine generator replaced with larger unit completed in May 2009.
Emissions Reduction (%)*	NO _x – 19.0%/38.8%* SO ₂ – 80.9%

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

	PM – 99.8%
	PM ₁₀ – 99.6%

*Emissions Reduction estimated by comparing pre-control upgrade 2006-2008 CAMD data to AP-42 emission factor data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (June 2009 – June 2010). For PM/PM₁₀, uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See “Craig APCD Technical Analysis” for further details. Not based on actual testing.

II. Source Emissions

Table 2 summarizes the NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA’s CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado’s APEN’s submitted by the facility and as applicable, EPA’s CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Craig Station

NO _x (tons/year)	SO ₂ (tons/year)	PM ₁₀ (tons/year)
16,942	3,769	363

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Craig Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 1	SO ₂ (tons)	865.1	1053.0	990.5	969.5
	SO ₂ (lb/ MMBtu)	0.06	0.06	0.06	0.06
	NO _x (tons)	4665.7	5817.3	5056.9	5180.0
	NO _x (lb/ MMBtu)	0.34	0.32	0.30	0.32
	PM (tons)	92.9	107.3	101.1	100.4
	PM (lb/ MMBtu)	0.007	0.006	0.006	0.006
Unit 2	SO ₂ (tons)	999.6	797.1	1149.1	981.9
	SO ₂ (lb/ MMBtu)	0.05	0.05	0.06	0.06
	NO _x (tons)	5548.7	4965.7	5566.4	5360.3
	NO _x (lb/ MMBtu)	0.30	0.32	0.30	0.31
	PM (tons)	90.7	81.9	87.5	86.7
	PM (lb/ MMBtu)	0.005	0.005	0.005	0.005
Unit 3	SO ₂ (tons)	1721.3	1948.5	1782.6	1817.5
	SO ₂ (lb/ MMBtu)	0.10	0.11	0.11	0.10
	NO _x (tons)	6592.1	6670.1	5943.9	6402.0
	NO _x (lb/ MMBtu)	0.38	0.36	0.35	0.37
	PM (tons)	70.4	71.8	67.7	70.0
	PM (lb/ MMBtu)	0.004	0.004	0.004	0.004
Auxiliary Boiler (130 MMBtu/hr) Fuel Oil Boiler	SO ₂ (tons)	0	0	0	0
	SO ₂ (lb/ MMBtu)	0	0	0	0
	NO _x (tons)	0	0	0	0

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Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
	<i>NO_x (lb/ MMBtu)</i>	0	0	0	0
	<i>PM (tons)</i>	0	0	0	0
	<i>PM (lb/ MMBtu)</i>	0	0	0	0
<i>F101a – Coal Hauling – Units 1 & 2</i>	<i>PM (tons)</i>	8.15	8.15	11.39	9.23
<i>F101b – Coal Unloading to Grizzly – Units 1 & 2</i>	<i>PM (tons)</i>	0.04	0.04	0.05	0.04
<i>F101c – Coal Surge Pile</i>	<i>PM (tons)</i>	0.05	0.05	0.05	0.05
<i>S101d – Primary Coal Crushing – Units 1 & 2</i>	<i>PM (tons)</i>	0.18	0.18	0.23	0.20
<i>S101e – Secondary Coal Crushing Bldg – Units 1 & 2</i>	<i>PM (tons)</i>	0.46	0.46	0.56	0.49
<i>S101f – Common Coal Transfer Bldg Belt A</i>	<i>PM (tons)</i>	0.001	0.001	0.0013	0.0011
<i>S101g – Common Coal Transfer Bldg Belt B</i>	<i>PM (tons)</i>	0.001	0.001	0.0013	0.0011
<i>S101h – Coal Stackout Building – Units 1 & 2</i>	<i>PM (tons)</i>	0.002	0.002	0.0025	0.0022
<i>S101i – Coal Stackout – Units 1 & 2</i>	<i>PM (tons)</i>	0.051	0.051	0.063	0.055
<i>F101 j -Coal Storage Piles – Units 1 & 2</i>	<i>PM (tons)</i>	0.63	0.63	0.63	0.63
<i>S101k – Coal Reclaim A – Units 1 & 2</i>	<i>PM (tons)</i>	0.0018	0.0018	0.0019	0.0018
<i>S101l – Coal Reclaim B – Units 1 & 2</i>	<i>PM (tons)</i>	0.0018	0.0018	0.0019	0.0018
<i>S101m – coal Tripper Deck & Silos – Units 1 & 2</i>	<i>PM (tons)</i>	0.0036	0.0036	0.0038	0.0037
<i>S101n – Common Coal Drive House</i>	<i>PM (tons)</i>	0.0036	0.0036	0.0038	0.0037
<i>S203a – Fly Ash Storage Silo A – Units 1 & 2</i>	<i>PM (tons)</i>	0.0047	0.0047	0.002	0.0038
<i>S203b – Fly Ash Storage Silo B – Units 1 & 2</i>	<i>PM (tons)</i>	0.0047	0.0047	0.002	0.0038
<i>F203c – Fly Ash Truck Loading – Units 1 & 2</i>	<i>PM (tons)</i>	0.0079	0.0079	0.0034	0.0064
<i>P204 – Ash Hauling & Storage – Unit 3</i>	<i>PM (tons)</i>	62.2	62.2	62.2	62.2
<i>P201 – Limestone Hauling</i>	<i>PM (tons)</i>	14.7	14.7	17.5	15.6
<i>F102a – Coal Train Unloading – Unit 3</i>	<i>PM (tons)</i>	0.0607	0.0607	0.0676	0.063
<i>S102b/c – Coal Conveyor Portal Building – Unit 3</i>	<i>PM (tons)</i>	0.003	0.003	0.0034	0.0031
<i>S102d – Secondary Coal Crushing (2 crushers) – Unit 3</i>	<i>PM (tons)</i>	0.68	0.68	0.76	0.71
<i>S102e – Coal Stackout Building – Unit 3</i>	<i>PM (tons)</i>	0.003	0.003	0.0034	0.0031
<i>F102f – Coal Stackout – Unit 3</i>	<i>PM (tons)</i>	0.076	0.076	0.085	0.078

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Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
<i>F102g – Coal Storage Pile – Unit 3</i>	<i>PM (tons)</i>	<i>0.24</i>	<i>0.24</i>	<i>0.24</i>	<i>0.24</i>
<i>S102h – Coal Reclaim System – Unit 3</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102k – Common Coal Transfer Building Extension</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102n – Common Coal Drive House</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102i – Coal Tripper Deck and Silos – Unit 3</i>	<i>PM (tons)</i>	<i>0.0018</i>	<i>0.0018</i>	<i>0.0018</i>	<i>0.0018</i>
<i>S102j – Loadout Coal to Railcars – Unit 3</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>F205a – Ash Hauling to “Landfill” (Outage Waste to Trapper)</i>	<i>PM (tons)</i>	<i>0.114</i>	<i>0.114</i>	<i>0.114</i>	<i>0.114</i>
<i>F205b – Ash and Wet Waste Hauling to/from Decant Basin</i>	<i>PM (tons)</i>	<i>0.676</i>	<i>0.676</i>	<i>0.676</i>	<i>0.676</i>
<i>F205c – Ash Unloading at “Landfill” (Outage Waste) & Ash Unloading at Decant Basin</i>	<i>PM (tons)</i>	<i>0.0024</i>	<i>0.0024</i>	<i>0.0024</i>	<i>0.0024</i>
<i>F205d – Wet Waste Unloading at Decant Basin</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>F202a – Lime Hauling (trucks)</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>S202b – Lime Unloading – Unit 3</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S202c – Lime Conveying & Silo – Unit 3</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S202d – Lime Day Bin</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S401/2 – Cooling Towers – Units 1 & 2</i>	<i>PM (tons)</i>	<i>10.3</i>	<i>10.3</i>	<i>10.3</i>	<i>10.3</i>
<i>Auxiliary Boiler</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>S403 - Cooling Tower – Unit 3</i>	<i>PM (tons)</i>	<i>5.8</i>	<i>5.2</i>	<i>5.2</i>	<i>5.4</i>

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day NO_x rolling averages for the boilers are estimated to be 5-15% higher than the annual average emission rate.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Tri-State estimated that a realistic depiction of anticipated annual emissions for Unit 3, or “Baseline” Emissions”, to be conservative, was the average of 30-day averages from 2009, or 0.33 lb/MMBtu for NO_x. Tri-State noted that this baseline reflects the recent PSD permit limit of 6,752 tons associated with a 2009 turbine upgrade. This baseline reflects the low-NO_x burners and overfire air installed at Craig 3 in 2009. The Division notes that the 2006 – 2008 baseline period used for other RP and BART sources is not reasonable for Craig Unit 3 due to the recent upgrades. The Division also used the recent PSD permit limit of 6,752 tons for NO_x and 2,125 tons for SO₂ to determine a baseline.

The notable difference is that the Division used the average capacity factor (based on heat input) from 2006 – 2008 to determine the baseline emissions, resulting in 0.28 lb/MMBtu for NO_x and 0.09 lb/MMBtu for SO₂. Craig Unit 3 ran at an average of 86.4% capacity (based on heat input) from 2006 – 2008, thus this factor is assumed to be a reasonable baseline for this planning period. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 4.

Table 4: Tri-State Craig Unit 3 Baseline Emissions

Pollutant	Unit 3	
	Annual Emissions* (tpy)	Average Emissions (lb/MMBtu)
NO _x	5,693	0.283
SO ₂	1,792	0.089
PM ₁₀	148**	0.007**

*The Division calculated annual (tpy and lb/MMBtu) NO_x and SO₂ emissions using 2006 – 2008 capacity factor and current PSD permit limits.

**The PM₁₀ emissions and emissions factor are from August 2009 stack test data; PM₁₀ current construction permit annual emission limit is 403 tons/year and 0.012 lb/MMBtu.

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. The Trapper contract expires in 2014. Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 3 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 3 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 6. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals. The actual APEN coal specifications (2006 – 2008) are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Craig Unit 3	10,224	0.39	6.47

Table 6: Craig Station Coal Specifications (2008)

Coal Mine/Region	Colowyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H ₂ O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57

Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 7. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 7: Uncontrolled emission factors for Craig BART-eligible sources²

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Unit 3	12	14.7	64.7	14.9

*SO₂ and PM/PM₁₀ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to “Craig APCD Technical Analysis” for more details.

IV. Reasonable Progress Evaluation of Unit 3

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

The Division requested that Tri-State evaluate the option below, and received relevant information for this request on June 4, 2010:

Dry FGD upgrades

As discussed in EPA’s BART Guidelines³, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

The current PSD permit SO₂ limits are depicted in Table 8.

Table 8: Craig Unit 3 SO₂ PSD Permit Limits

	SO ₂ limits (lb/MMBtu)	Reduction (%) Required	Annual Emission Limit (tons/year)
	Calendar day average	30-day rolling	
Unit 3	0.20*	80	2,125

*May be exceeded once during any calendar month.

² EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

³ EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power plants⁴. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO₂ by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and then collected in a particulate control device.

Craig Unit 3 was installed in 1984 with a “Spray Dryer Removal System” in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO₂ removal from the gaseous emission stream of a utility boiler. Tri-State has since upgraded this system (between 2007 and 2009) and currently achieves greater than 80% SO₂ removal, with an actual annual average of approximately 0.09 lb/MMBtu. This system exceeds EPA’s presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu⁵. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA’s RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to “Division RBLC Analysis” for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO₂ emissions found that lime spray drying processes have a median design efficiency of 90%⁶.

The BART Guidelines note potential upgrades for dry scrubbing systems⁷. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

Tri-State examined BART-guideline dry scrubbing potential upgrades, with the following results:

- Use of performance additives: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO₂ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

⁴ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

⁵ Colorado Operating Permit 96OPLR142 pg. 5 – SO₂ 30-day rolling average limit is 0.13 lb/MMBtu.

⁶ EPA, 2000. “Controlling SO₂ Emissions: A Review of Technologies.” Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.

⁷ EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39171.

-Use of more reactive sorbent/Increase the pulverization level of sorbent: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent.

-Engineering redesign of atomizer or slurry injection system: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO₂ removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Unit 3. However, the Division has evaluated the option of tightening the SO₂ emission limit for Craig Unit 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limit on Craig Unit 3 has been evaluated by the Division. The Division analyzed the period after Tri-State upgraded the turbine (post-control: June 2009 – June 2010) against baseline emissions (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 9, to determine potential control effectiveness, if any. Additionally, the Division evaluated the baseline heat input, capacity factor, and hours of operation pre-upgrade (2006 – 2008) and post-upgrade (June 2009 – June 2010) to evaluate whether the data was consistent with baseline information, and whether there was enough information to determine if a tighter emission limit is warranted, in Table 10. This information allows the Division to set a more relevant emission limit for Craig Unit 3 using representative actual emissions.

Table 9: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate post-control (lb/MMBtu)
Craig Unit 3 – post control (June 2009 – June 2010)	0.1350	0.1081
Craig Unit 3 – pre-control (2006 – 2008)	0.1412	0.1088

Table 10: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Capacity Factor (Heat Input %)	Hours of Operation (% of total possible operating hours)
Craig Unit 3 – June – December 2009	98.1%	95.5%
Craig Unit 3 – January – June 2010	89.7%	96.1%
Craig Unit 3 – June 2009 – June 2010 Average	93.9%	95.8%
Craig Unit 3 – pre-control (2006 – 2008)	86.4%	96.3%

The Division notes that there are not significant differences between the maximum or average 30-day rolling emissions before and after the turbine and control upgrades. Similarly, the capacity factor and hours of operation do not change discernibly. Therefore, the Division concludes that post-upgrade operations may be used in determining a tighter SO₂ emission limit in this reasonable progress.

Table 11 summarizes each available technology options and technical feasibility for SO₂ control on Craig Unit 3.

Table 11: Craig Unit 3 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90% ⁸	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO ₂ control
Fuel switching – different coal type	None	Y – will not provide further SO ₂ control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N

⁸ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

A more stringent emission limit is not anticipated to result in any increased costs. Thus, this factor does not influence the selection of controls.

Factor 2: Time Necessary for Compliance

A more stringent emission limit is not anticipated to result in any system upgrades or changes and can be implemented as soon as the SIP is approved. Thus, this factor does not influence the selection of controls.

Factor 3: Energy and Non-Air Quality Impacts

There is not any negative energy or non-air quality impacts related to a more stringent emission limit. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 12 shows the number of days pre- and post-control. Table 13 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in \$/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Table 12: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour SO2 rates	3	0.326	Mt. Zirkel Wilderness	239	---	---	173	---	---
Dry FGD	3	0.150		239	233	6	173	170	3
Dry FGD	3	0.070		239	230	9	173	168	5

Table 13: Visibility Results – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour SO ₂ rates	3	0.326	5.20	---	---
Dry FGD	3	0.150	4.94	0.26	5%
Dry FGD	3	0.070	4.82	0.38	7%

Step 6: Select RP Control

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO₂ limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets Division website, the state has determined that this emissions rate is achievable without additional capital investment.

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ RP is dry FGD controls at the following SO₂ emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

An SO₂ limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

B. Filterable Particulate Matter (PM₁₀)

Craig Unit 3 is equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 14 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >95% control. The current Colorado construction permit limit is 0.013 lb/MMBtu for filterable PM emissions and 0.012 lb/MMBtu for filterable PM₁₀ emissions and also limits total PM and PM₁₀ (filterable and condensable) emissions to 0.022 and 0.020 lb/MMBtu respectively (Condition 4). The most recent stack test data is used to determine

compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 14: Craig Unit 3 Stack Test Results (August 2009)

Pollutant	Unit 3 (lb/MMBtu)
Total PM	0.013
Filterable PM	0.0091
Condensable PM	0.0035
Total PM ₁₀	0.007
Filterable PM ₁₀	0.0035
Condensable PM ₁₀	0.0035
PM Control efficiency	99.5%
PM ₁₀ Control efficiency	98.8%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The State has determined that the existing Unit 3 fabric filter baghouse and regulatory emissions limit of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM₁₀) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM₁₀.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

Tri-State identified five options for NO_x control:

New/modified Low NO_x Burners (LNBs) with Overfire Air (OFA) system (next generation)

Advanced OFA system or Rotating overfire Air (ROFA)

Neural network system combustion controls

Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)®

Rich Reagent Injection (RRI)

Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

LNBs with OFA Upgrades: TriState contracted with ACT to modify the existing Craig 3 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-NO_x Babcock & Wilcox 4Z burners such as those in use at Craig Unit 3. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT

upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that “to give a guaranteed NO_x reduction, a lot more information is required.” LNBs modifications with OFA upgrades appear to be technically feasible for Craig Unit 3.

Advanced OFA system – rotating overfire air system (ROFA): ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

TriState contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Unit 3. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load⁹. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 3 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit’s distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 3 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. TriState states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Unit 3.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Unit 3. Tri-State conducted a site-specific SNCR study

⁹ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, a retrofit SCR system, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the unit cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Unit 3.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler¹⁰ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers¹¹ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/SOFA/LNB+SOFA: Craig Unit 3 is equipped with low-NO_x burners with over-fire air (LNB+OFA) as part of a construction permit modification.

Table 1 illustrates that this system achieves about 39% NO_x reductions (based on actual emissions) on Unit 3.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu¹². However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

¹⁰ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

¹¹ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

¹² Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers." <http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,¹³ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Unit 3 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: TriState noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between “design criteria” versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: TriState noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control. B&V explains that the reduction in control efficiency is due to the difference between “design criteria” versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

¹³ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rate for Craig Unit 3 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu¹⁴ or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).¹⁵ EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. Table 15 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

Table 15: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 3	0.283	71.8	75.2	0.080	0.070

Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: Craig Unit 3 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Ultra-Low NO _x Burner (ULNB) Upgrade/Refinements	0 – 2% (TriState)	Y
Neural network system	0 – 5% (TriState)	Y
SNCR	10 – 40%	Y
Rotating overfire air (ROFA)	45 – 65%	N
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N

¹⁴ Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

¹⁵ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Low NO_x burner upgrades: Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low NO_x burners with overfire air. Ultra-low NO_x burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.¹⁶ Tri-State estimates that the initial cost of combustion control refinement at about \$2,200,000 with an annualized 20-year cost of \$122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

Neural network system: TriState did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that TriState contacted.¹⁷ It is unknown why TriState will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about \$800,000 with an annualized 20-year cost of \$280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.¹⁸ The Tri-State-estimated SNCR costs for operating expenses are 70% for Craig Unit 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.¹⁹

¹⁶ Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NO_x Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

¹⁷ NeuCo White Papers and Case Studies. <http://www.neuco.net/library/case-studies/default.cfm> and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NO_x Emission Control Cost and Technical Feasibility Information."

¹⁸ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

¹⁹ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

The cost effectiveness for SNCR on Unit 3 (at 15% control efficiency) is approximately \$4,887 per ton. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (comparable to Unit 3) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing \$590 - \$1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{20,21} It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.²² On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately \$2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division inquired about the reagent and auxiliary power costs; Tri-State responded on July 30, 2010 adjusted the auxiliary power and lost generation costs for all of the Craig Units for both SNCR and SCR. Tri-State also provided further information regarding the cost of potential reagent options. The costs for these two items remain higher than other Colorado facility estimates; however, Tri-State has provided adequate information detailing the reasoning for power and reagent costs. The Division and Tri-State still do not completely concur on other cost items, including an annual 3% escalation rate for capital material, capital labor, capital indirect, and operation and maintenance. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division will use Tri-State's capital and operation/maintenance costs for this analysis in the absence of additional information at this time.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing \$1,700 - \$3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{23,24 25,26} It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately \$7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 17 and Table 18 depict controlled NO_x emissions and control cost comparisons.

²⁰ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²¹ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²² EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.” <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

²³ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁴ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

²⁵ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

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²⁶ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 17: Craig Unit 3 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,693	0.283	
Combustion control refinements	2	5,579	0.277	0.32
Neural network system	5	5,408	0.268	0.31
SNCR	15	4,839	0.240	0.28
SCR	75	1,412	0.070	0.08

Table 18: Craig Unit 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Combustion control refinements	114	\$122,000	\$1,071	\$1,071
Neural network system	285	\$280,000	\$984	\$925
SNCR	854	\$4,173,000	\$4,887	\$4,887
SCR	4,281	\$29,762,387	\$6,952	\$7,466

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state’s experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour 2nd	3	0.365	Mt. Zirkel Wilderness	239	---	---	173	---	---

half 2009 NOx rate									
2009 New LNBs	3	0.283		239	234	5	173	170	3
SNCR	3	0.240		239	233	6	173	166	7
SCR	3	0.070		239	224	15	173	149	24

Table 20: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour 2nd half 2009 NOx rate	3	0.365	5.20	---	---
2009 New LNBs	3	0.283	4.99	0.21	4%
SNCR	3	0.240	4.88	0.32	6%
SCR	3	0.070	4.41	0.79	15%

Step 6: Select RP Control

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Craig Unit 3 is SNCR control at the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

For SNCR at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: \$4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan.

V. Reasonable Progress Evaluation of Ash Hauling & Storage (P204) and Limestone Hauling (P201)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 96OPMF155.

Ash hauling (P204) is controlled with two methods to minimize fugitive emissions:

- Ash deposited in trucks for transport to disposal areas shall be sufficiently moist (Condition 8.2).
- The scrubber sludge/ash haul road servings Units 1, 2, and 3 shall be treated with magnesium chloride or equivalent as a dust suppressant. The magnesium chloride shall be applied according to manufacturer's specifications. The frequency of application shall be according to manufacturer's recommendations (Condition 8.3).

Limestone hauling (P201) activities are controlled several ways to minimize fugitive emissions:

- Opacity limitations of 20% except under certain operational conditions (U.S. EPA Reference Method 9) (Conditions 6.2, 11.2, and 11.3)
- Unloading facilities are vented to a baghouse (Condition 6.3)
- All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their in the pollution control system (Condition 6.4)

These existing controls and corresponding emission limits in Section II, Conditions 6 and 8 of Operating Permit 96OPMF155 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

VI. Reasonable Progress Evaluation of Units 1 & 2

Units 1 and 2 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Units 1 and 2 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO₂, and PM/PM₁₀ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO₂, or PM/PM₁₀ for Units 1 and 2 at Craig Station.

HEATER-TREATER SOURCE CATEGORY

NOx Emission 4-Factor Analysis for Reasonable Progress (RP)

I. Source Description

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to the gas plant. Generally, the contaminants include liquid hydrocarbons and water. The composition of the liquid hydrocarbons (oil and condensate) can vary by gas field but the majority of gas wells in Colorado are located in the Denver-Julesburg (DJ) Basin which produces a condensate liquid.

The heater-treater is a combination of a heater, free-water knockout, and oil/condensate and gas separator. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead. Since chokes in the wellhead restrict the flow of the oil and gas from the well, temperatures may drop due to the pressure changes of the choke. This may cause the water or hydrates to freeze and plug the well, thereby slowing or stopping the condensate and gas production. Two diagrams at the end of this document show examples of heater-treaters.

Information regarding heater-treater emissions and control strategies is scarce. The paucity of information is likely due to the very low emissions associated with each heater-treater that very often falls below regulatory thresholds. However, the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018.

II. Heater-Treater Source Category Emissions - Statewide

Pollutant	Heater-Treater Emissions (tpy)	2018 Annual Emissions (tpy)
CO	0.18 ¹	4,809
NO ₂	0.88 ¹	22,901
PM ₁₀	negligible ²	negligible
SO ₂	Negligible ³	negligible

Notes:

1. Source: "Final Report – Oil and Gas Emission Inventories for the Western States", by ENVIRON International Corporation for Western Governors' Association, December 27, 2005
2. Source: AP-42, 5th Edition, Volume 1, Chapter 1, Section 1.4.3
3. Source: "A Comprehensive Oil and Gas Emissions Inventory for the Denver-Julesburg Basin in Colorado," by ENVIRON International Corporation, May 2008

III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Five technologies have been identified to lower NOx emissions from heater-treaters:

Technology #1 - Lowering the heater-treater temperature

Technology #2 - Installing insulation on the separator

Technology #3 - Retrofitting with low-NO_x burners

Technology #4 - Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

Technology #5 - Using central gathering facilities

Technology #1: This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."

Technology #2: This technology (installing insulation on the separator) was identified by the Four Corners Air Quality Task Force in 2007. This technology would reduce combustion emissions because it would reduce fuel use.

Technology #3: This technology (retrofitting with low-NO_x burners) was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th Edition, Volume 1, Chapter 1, Section 1.4.4: "Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation."

Technology #4: This technology (adding NSCR or SCR) involves adding post-combustion control equipment to treat engine exhaust.

Technology #5: This technology (central gathering facilities) is being used by some companies, including in the Piceance Basin and in the Jonah/Pinedale region of Wyoming. Other terms include central collection facilities, liquid gathering systems, or 3-phase gathering systems. In some cases, produced natural gas is separated into two or three phases (gas and liquids [produced water and condensate] or gas, produced water, and condensate) at the wellhead and those liquid streams are sent to central gathering facilities. In other cases, including a facility in the Piceance Basin, produced gas (including the liquids) is sent directly to the central gathering facilities. In those cases, emissions from heater-treaters would be reduced because fewer heater-treater devices would be required.

Step 2: Eliminate Technically Infeasible Options

Technology #1: This technology is technically feasible.

Technology #2: This technology is technically feasible.

Technology #3: The Four Corners Air Quality Task Force considered low NO_x burners as a mitigation option for the Four Corners area and had the following finding: “Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction.” It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO_x burners are not commercially available for very small combustion sources such as heater-treaters.

Technology #4: A heater-treater is a combustion device that is similar to internal combustion engines where the application of NSCR and SCR on engines smaller than 100 hp is not practical or technically feasible. Moreover, the cost per unit of power is higher, and there are uncertainties as to whether the proper exhaust temperature for optimum performance can be reliably maintained. Consequently, NSCR and SCR may not be commercially available for many small engines. (source: Four Corners Air Quality Task Force document available at www.nmenv.state.nm.us/aqb/4C/Docs/ArgonneRICEmat.DOC). Similarly, for small fuel burning equipment, such as heater-treaters, the availability of post combustion controls is anticipated to be unavailable and therefore technically infeasible.

Technology #5: This technology is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Technology #1: The EPA Natural GasSTAR in PRO Fact Sheet No. 906 regarding lowering heater-treater temperatures was written from the methane reduction perspective. Emission reductions for NO₂ and CO were not provided.

Technology #2: The Four Corners Air Quality Task Force did not provide the control effectiveness of installing insulation and additional information on the effectiveness of such control appears to be unavailable.

Technology #5: Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Technology #1 - Lowering the heater-treater temperature: Although the EPA Natural GasSTAR fact sheet was written with methane reductions in mind, the costs of implementing the control technology also applies to combustion emission reductions. Capital costs range from \$1,000 to \$10,000. Annual operating and maintenance costs are \$100 to \$1000. The payback, through incremental labor and fuel gas savings, is less than one year.

Technology #2 - Installing insulation on the separator: Installing insulation on heater-treaters will reduce fuel usage and is economically feasible where there is a payback that meets an operators respective investment targets (e.g., ROI or NPV). For older units where the remaining life of the equipment is limited, the economics may not justify the application of insulation.

Technology #5 – Centralized gas well gathering facilities to reducing the number of Heater-Treaters: The cost of removing a group of heater-treaters and replacing them with a central gathering facility will vary due to many parameters, including topography, composition of the produced natural gas, number of heater-treaters being removed, and mineral rights. Topography may cause difficulties in dealing with large slugs of liquids; frequent pigging may be required to move liquids to the central gathering facility. It would be more cost efficient to implement this technology on a new field, rather than retrofitting an existing field that already has infrastructure based on wellhead separation. Typically when a well is drilled there are multiple ownerships in the well due to land and mineral rights. This requires that volumes be allocated back to each specific well for proper royalty treatment. To track this requires equipment at each well, which increases capital and operating costs and reduces the savings from eliminating equipment at each wellhead. This allocation issue goes away when a company owns all associated mineral and land rights. Cost savings include recovery of product that was previously lost to the atmosphere, reduced truck traffic to wellheads, and reduction of condensate and water tanks.

Factor 2: Time Necessary for Compliance

Technology #1 - Lowering the heater-treater temperature: Additional time for achieving compliance with this technology is not anticipated.

Technology #2 - Installing insulation on the separator: Additional time for achieving compliance with this technology is not anticipated.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: The additional time necessary to comply with centralizing gas well gathering would be very site specific and would likely vary depending on gas well density and topographical barriers.

Factor 3: Energy Impacts and Non Air-Quality Environmental Impacts

Technology #1 - Lowering the heater-treater temperature: Lowering the heater-treater temperature will reduce fuel use. There are not any non air-quality impacts.

Technology #2 - Installing insulation on the separator: Installing insulation on heater-treaters will reduce fuel use. There are not any non air-quality impacts.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: It is more energy efficient to operate a central gathering facility rather than multiple individual heater-treaters. There are not any non air-quality impacts.

Factor 4: Remaining Useful Life

Technology #1 - Lowering the heater-treater temperature: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

Technology #2 - Installing insulation on the separator: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) If heater-treaters were removed and replaced with a central gathering facility, the heater-treaters would not be used for their entire service.

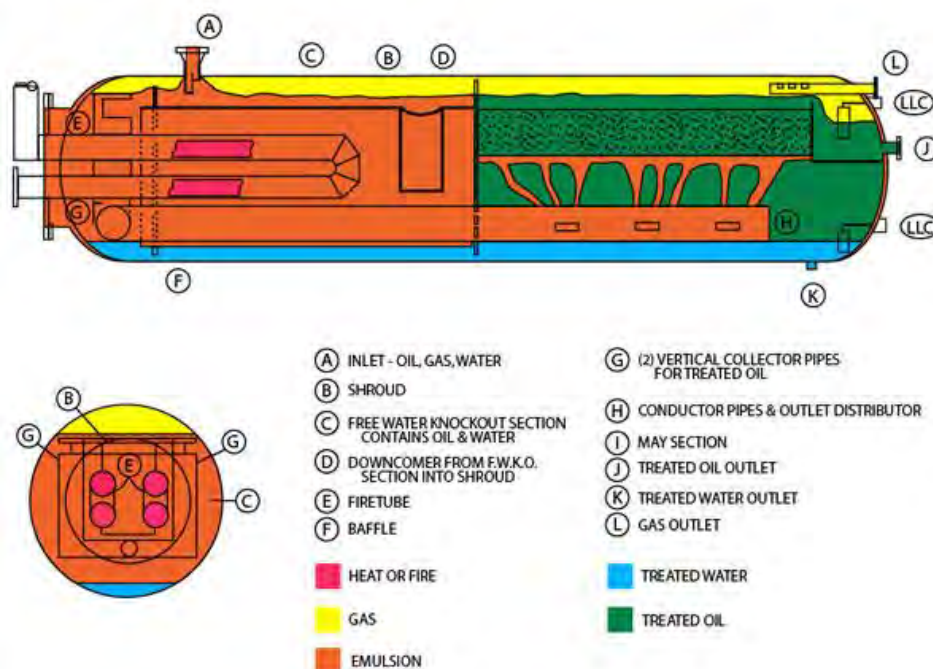
Step 5: Select Reasonable Progress Control

Currently, heater treaters are not regulated (issued permits) by the Division as they fall under an exemption for fuel burning equipment that uses gaseous fuel and has a design rate of less than or equal to 5 million BTUs/hour (AQCC Regulation 3, Part A, II.D.1.k). Generally, reports from source operators (provided to the Division on emission inventory reporting forms) indicate that a typical heater-treater design rate is about half of the exemption threshold.

Due to the lack of sufficient data, the Division is not able to make a control technology determination for heater-treaters in this planning period. The Division intends to reassess this category in the next planning period.

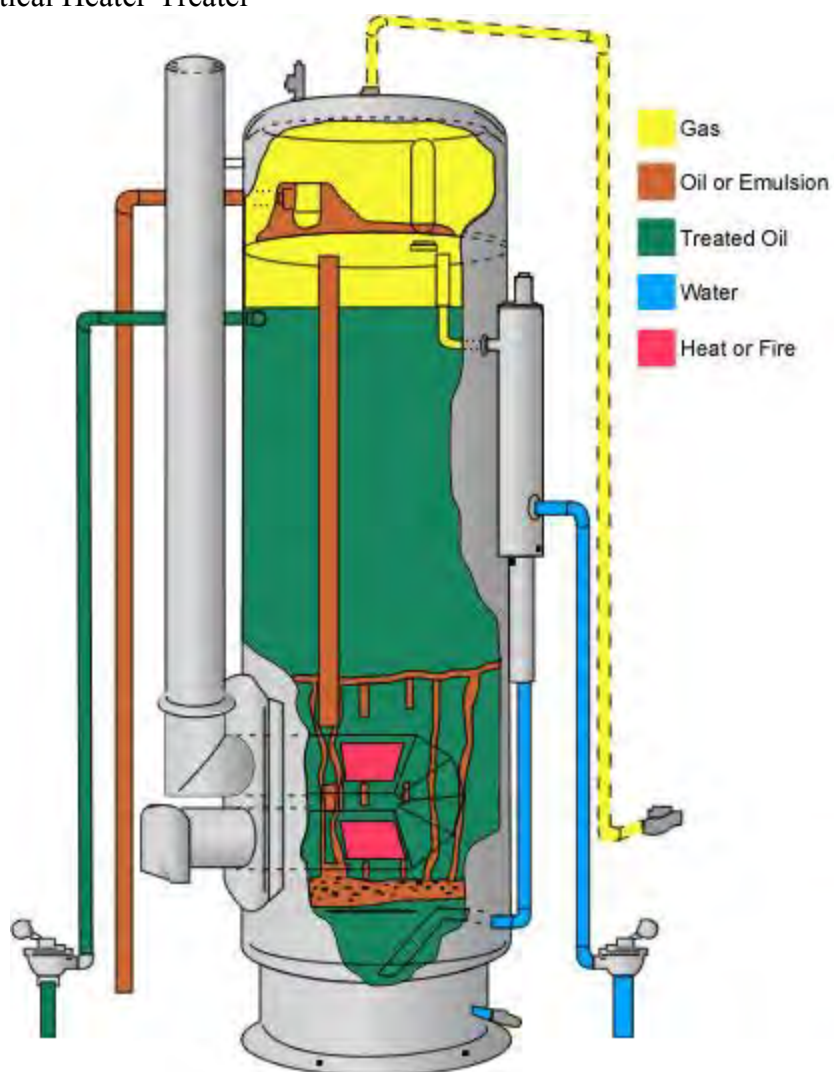
The below diagrams provide basic information on the typical heater-treater designs.

Diagram 1: Horizontal Heater-Treater



This diagram was provided by KW International. Further explanation about heater-treaters is available at <http://www.kwintl.com/oil-treating.html>.

Diagram 2: Vertical Heater-Treater



This diagram was provided by KW International. Further explanation about heater-treaters is available at <http://www.kwintl.com/oil-treating.html>.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Holcim Portland Plant, Florence, Colorado**

I. Source Description

Owner/Operator: Holcim (US) Inc.
Source Type: Portland Cement Manufacturing (dry process)
SCC (Cement Plant): 30500623
Kiln Type: Preheater/Precalciner Kiln

The Holcim Portland plant is located in Fremont County on Highway 120 near the town of Florence, Colorado, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park. Figure 1 below provides an aerial perspective of the Portland Plant site.

Figure 1: Holcim Portland Plant Aerial Perspective



In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_x, SO₂, and PM/PM₁₀ emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 mmBtu per hour of fuel input with nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM₁₀, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO₂, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_x precalciner, indirect firing, Low-NO_x burners, staged combustion and a Linkman Expert Control System for NO_x, and by the use of good combustion practices for both NO_x and SO₂.

For this analysis, the Division also relied on the existing construction permit, historical information regarding the Holcim facility, and information about similar facilities to determine RP for NO_x, SO₂, and PM₁₀. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a de minimis threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration (PSD) levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility,

equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control¹.” These levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM10 emissions exceed the PSD significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis for the Portland Plant, though it did submit limited information on the feasibility of post-combustion NOX controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. The previous September 14, 2010 version of this document has been revised to reflect this additional information.

II. Source Emissions

Table 1 summarizes the NOX, SO2 and PM10 actual emissions for the period of 2007-2009. Table 2 summarizes each unit at the facility and applicable NOx, SO2 and PM10 actual emissions.

Table 1 – Summary of Plant-Wide Emissions

Year	Pollutant (1, 2)		
	PM10 (tpy)	NOx (tpy)	SO2 (tpy)
2007	262.05	2,447.30	189.80
2008	268.98	2,294.60	306.66
2009	183.26	1,251.66	297.14

Notes:

- (1) Emission data from CDPHE – PTS data base.
- (2) Annual emissions are less than permitted emissions due in part to economic conditions resulting in less than full production.

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Table 2 – Summary of Emissions by Unit Process

AIRS ID	Process	Pollutant	Emissions(2,3) (tons per year)			
			2007 (1)	2008	2009	Average
101A	Top soil removed Topsoil hauled Wind erosion	PM10 (fug)	----	1.14	0.57	0.855
101B	Explosives	PM10 (fug) NOx SO2	----	0.29 7.47 0.88	0.20 4.99 0.59	0.245 6.23 0.735
101C	Overburden removed/hauled	PM10 (fug)	----	14.43	11.41	12.92
101D	Raw material removed/hauled	PM10 (fug)	----	25.91	16.68	21.295
101E	CKD disposed/hauled	PM10 (fug)	----	0.40	0.60	0.50
101F	Disturbed Area	PM10 (fug)	----	83.61	83.61	83.61
101G	Mined land Reclamation	PM10 (fug)	----	0	0	0
102A	Unload Crusher #1	PM10 (fug)	----	0.01	0	0.005
102B	Unload Crusher #2	PM10 (fug)	----	0.01	0.01	0.01
102C	Crusher #1	PM10	----	0.03	0.02	0.025
102D	Transfer to secondary crusher	PM10	----	0.01	0	0.005
102E	Secondary crusher	PM10	----	0.02	0.01	0.015
102F	Crusher #2	PM10	----	0.64	0.41	0.535
102G	Transfer to storage silo	PM10	----	0.06	0.03	0.045
102H	Transfer to blending hall	PM10	----	0.19	0.13	0.16
102J	Transfer outside materials	PM10	----	0	0	0
102K	Pre-Blend Hall activities	PM10	----	0.18	0.11	0.145
102L	Transfer from Bins	PM10	----	0.15	0.10	0.125
103A	Coal unloaded	PM10 (fug)	----	0.98	0.68	0.83
103B	Coal Stockpile/Coal stored	PM10 (fug)	----	0.18	0.12	0.15
103C	Coal Handled	PM10	----	0.10	0.07	0.085
103D	Coal screened/. Crushed	PM10	----	0.09	0.06	0.075

AIRS ID	Process	Pollutant	Emissions(2,3) (tons per year)			
			2007 (1)	2008	2009	Average
103E	Coal Transferred	PM10	----	0.01	0.01	0.01
104	Unloading additives	PM10 (fug)	----	0.05	0.04	0.045
105	Coal transferred	PM10	----	0.01	0.01	0.01
106	Raw material Blend	PM10	----	0.15	0.10	0.125
107	Coal Mill	PM10	----	5.16	1.52	3.34
108	Raw Material Milled	PM10	----	4.28	2.76	3.52
109	Raw Meal Elevated	PM10	----	2.68	1.73	2.205
110	Raw Meal Handled	PM10	----	1.07	0.69	0.83
111	Kiln Operations	PM10	68.17	47.23	13.9	43.1
		NOx	2,439.7	2,287.04	1,246.55	1,931.1
		SO2	188.9	305.76	296.55	263.7
112	Cement clinker cooler	PM10	----	21.52	6.34	13.93
113	Cement clinker stored	PM10	----	0.05	0.03	0.04
114	Cement clinker handled	PM10	----	0.06	0.04	0.05
115	Total cement produced	PM10	59.62	52.12	37.61	32.38
116	Cement handled	PM10	----	1.78	1.29	1.485
117	Cement bagged	PM10	----	0.	0	0
118	Cement bulk loadout	PM10	----	2.04	1.32	1.68
119	Cement product hauled	PM10 (fug)	----	1.00	0.64	0.82
135	Clinker import	PM10	----	0	0	0
138	Tire shredder	PM10 (fug)	----	0.29	0.08	0.185
139	Clinker reclaim	PM10	----	0.26	0.08	0.17
142	Tire debader	PM10	----	0.01	0	0.005
		NOx	----	0.09	0.02	0.055
		SO2	----	0.	0	0
144	Tire shredder	PM10 (fug)	----	0.82	0.23	0.523
145	Clinker export	PM10 (fug)	----	----	0.02	0.02

Notes:

- 1) A different reporting format was used in 2007.
- 2) Production has been limited in recent years due to economic factors. The plant is permitted to produce up to 1,873,898 tons of clinker per year. Production in 2008 = 1,332,888 tons and in 2009 = 914,193 tons. Emissions would be higher if the plant were operating at its permitted production level.
- 3) For some emission points, permit limits have been decreased over the last several years so that current permit limits are now lower than historical actual emissions.

Because clinker production in 2009 was significantly lower than in previous recent years, due in large part to challenging economic conditions, the state instead included 2004 and 2005 in the baseline calculation to represent a more realistic depiction of anticipated annual production and emissions for the plant. Table 3 presents emissions and production data for the 2004, 2005, 2006, 2007 and 2008 baseline years:

Table 3 – Kiln System Production and Emissions (2004 through 2008)

Year	Actual Emissions/Production					Projected Annual Emissions at Full Production of 1,873,898 tpy clinker	
	NO _x (tons)	SO ₂ (tons)	Clinker (tons)	NO _x (lbs/ton)	SO ₂ (lbs/ton)	NO _x (tons)	SO ₂ (tons)
2004	2,741.3	780.6	1,641,423	3.34	0.95	3,129.6	891.2
2005	2,572.3	371.5	1,642,740	3.13	0.45	2,934.3	423.8
2006	3,098.0	366.4	1,686,451	3.67	0.43	3,442.3	407.1
2007	2,439.7	188.9	1,361,523	3.58	0.28	3,357.8	260.0
2008	2,287.0	305.8	1,332,888	3.43	0.46	3,215.3	429.9
Avg	2,627.7	402.6	1,533,005	3.43	0.51	3,215.8	482.4
Max	3,098.0	780.6	1,686,451	3.67	0.95	3,442.3	891.2

III. Units Evaluated for Control

As discussed above, the only emission points whose current permitted level of emissions exceed the *de minimis* thresholds are the kiln system, quarry and finish mill. These emission points will be evaluated as a part of this reasonable progress analysis. The other emission points at the Portland Plant will not be considered further.

IV. Reasonable Progress Evaluation of the Kiln System

A. Sulfur Dioxide (SO₂)

Step 1: Identify All Available Technologies

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. The wet lime scrubbing process involves passing the flue gas from the kiln system through a sprayed aqueous calcium-based suspension that is contained within the scrubbing device. In the wet lime scrubber, the SO₂ reacts with the scrubbing reagent to form CaSO₄ that is collected and retained as aqueous sludge. The sludge is then dewatered and disposed.

Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO₂ emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

Step 2: Eliminate Technically Infeasible Options

The currently installed combination of good combustion practices, the inherent scrubbing nature of the cement manufacturing process, and the wet lime scrubber represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective.

Factor 2: Time Necessary for Compliance

The controls are already installed and operating.

Factor 3: Energy and Non-Air Quality Impacts

Because there are no changes to the existing controls for SO₂, there are no associated energy and non-air quality impacts for this determination.

Factor 4: Remaining Useful Life

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO₂ emission rate of 99.17 pounds per hour (lbs/hour), a NO_x emission rate of 837.96 lbs/hour, and a PM₁₀ emission rate of 19.83 lbs/hour. The modeling indicated a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Because the baseline emission rates and proposed RP emission rates have been revised, this specific impact value is no longer directly associated with the emission rates discussed in this section. However, in any event, because no additional controls are proposed for SO₂ emissions, there is no visibility improvement associated with SO₂ emissions.

Determination

While the state has determined that the existing controls represent the top-level control technology, the state did assess the corresponding SO₂ emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO₂ from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO₂ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO₂). The actual kiln SO₂ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO₂ per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO₂. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO₂ per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO₂ value of 0.77 pound per ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO₂ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO₂ emission limit of 1.30 pounds per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO₂ per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO₂ per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Summary of SO₂ RP Determination for Kiln System

1.30 pounds of SO₂ per ton of clinker (30-day rolling average)

721.4 tons of SO₂ per year (12-month rolling total)

B. Filterable Particulate Matter (PM and PM₁₀)

Step 1: Identify All Available Technologies

The state has determined that the existing baghouses installed on the kiln system represent the most stringent control option. Baggouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter.

Holcim has reported nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

Step 2: Eliminate Technically Infeasible Options

The currently installed baghouses represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective.

Factor 2: Time Necessary for Compliance

The controls are already installed and operating.

Factor 3: Energy and Non-Air Quality Impacts

Because there are no changes to the existing controls for PM/PM₁₀, there are no associated energy and non-air quality impacts for this determination.

Factor 4: Remaining Useful Life

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

Factor 5 (optional): Evaluate Visibility Results

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO₂ emission rate of 99.17 lbs/hour, a NO_x emission rate of 837.96 pounds per hour (lbs/hour), and a PM₁₀ emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park.

As a part of our September 14, 2010 analysis, the state modeled possible visibility improvements associated with two emission rates – an emission rate of 0.08 pound of PM₁₀ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM₁₀ per ton of clinker (9.92 lbs/hour). This analysis assumed the emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change.

The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO₃) followed by sulfates (SO₄). The contribution of PM₁₀ to the total visibility impairment was insignificant in the analysis. The level of PM₁₀ emissions evaluated had no discernable impact on visibility.

Determination

While the state has determined that the existing controls represent the top-level control technology, the state did assess the corresponding PM₁₀ emissions rates. The facility is currently permitted to emit 246.3 tpy of PM₁₀ from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM₁₀ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM₁₀). The actual kiln system PM₁₀ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM₁₀ per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM₁₀ emissions from the kiln system on visibility impairment, the state has determined that no additional PM₁₀ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM₁₀ (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM₁₀ emissions.

Summary of PM/PM10 RP Determination for Kiln System

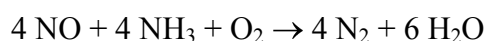
246.3 tons of PM10 per year (12-month rolling total)

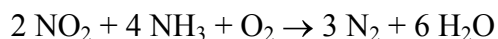
C. *Nitrogen Oxides (NOx)*

Step 1: Identify All Available Technologies

There are a number of technologies available to reduce NOX emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NOX emissions from Portland cement kilns. Additional discussion on SNCR is provided below:

For SNCR, within the relatively narrow temperature window of 1600 to 2000°F, ammonia (NH₃) reacts with NOx without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions:





Above this temperature range, the NH_3 is oxidized to NO_x , thereby increasing NO_x emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH_3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH_3 could be delivered to the kiln system through the use of anhydrous NH_3 , or an aqueous solution of NH_3 (ammonium hydroxide) or urea $[(\text{NH}_2)_2\text{CO}]$. A concern about application of SNCR technology is the breakthrough of unreacted NH_3 as “ammonia slip” and its subsequent reaction in the atmosphere with SO_2 , sulfur trioxide (SO_3), hydrogen chloride (HCl) and/or chlorine (Cl_2) to form a detached plume of PM_{10} – $\text{PM}_{2.5}$.

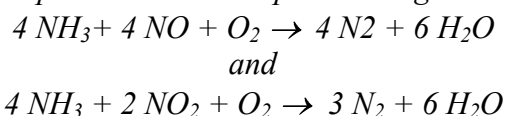
As part of this analysis, the state also considered the use selective catalytic reduction (SCR) as a NO_x control technology. The state has determined that SCR is not commercially available for the cement kiln system at the Holcim Portland Plant. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.” Based on our research and EPA’s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for the Holcim Portland Plant for purposes of this RP analysis. Additional information regarding SCR, as developed by the state as part of its BART analysis for the CEMEX Lyons plant is provided below:

SCR refers to the reduction of NO_x in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term “selective” refers to the unique ability of ammonia to react selectively with NO_x . The EPA released a NO_x control technology update for new cement kilns entitled “Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns,” EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce NO_x emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith

form) and promotes the NO_x reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C]), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:



The first equation is the predominant reaction because 90-95% of NO_x in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a NH₃: NO_x molar ratio of 1.05–1.1:1 to achieve a NO_x conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The NO_x removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to NO_x, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired NO_x reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:

After the PM control device – a “low-dust” system

After the last cyclone without ducting – a “high-dust” system.

The advantages of a “low-dust” system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 mg/m³ (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm³ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m³. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.

The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.

The design of a SCR system is expected to be site specific. According to Schreiber², the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 2, from Granger³ shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NO_x reduction efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350°C to 450°C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NO_x reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

Figure 2: Catalyst Performance for NO_x Control and Ammonia slip at Various Temperatures

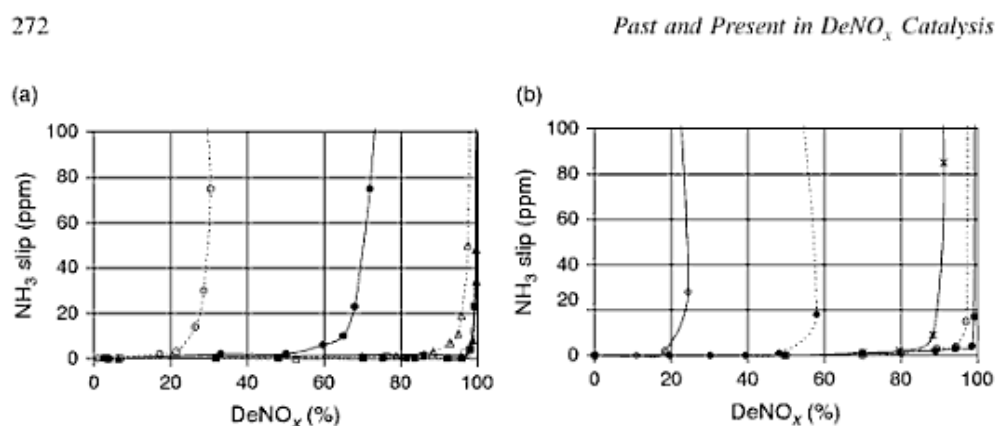


Figure 9.9. Performance of a coated V_2O_5/WO_3-TiO_2 SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) $NO:NO_2 = 1:1$. ($\diamond$) 120°C, ($\blacklozenge$) 150°C, ($*$) 180°C, ($\circ$) 200°C, ($\bullet$) 250°C, ($\blacktriangle$) 300°C, ($\triangle$) 350°C, ($\square$) 400°C, and ($\blacksquare$) 450°C. Cell density: ≈ 400 cpsi. $V_{cat} = 7.5$ cm³. Model gas investigation with 10% O₂, 5% H₂O, 1000 ppm NO or 500 ppm NO + 500 ppm NO₂, 0–1500 ppm NH₃, and balance N₂ in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 h⁻¹.

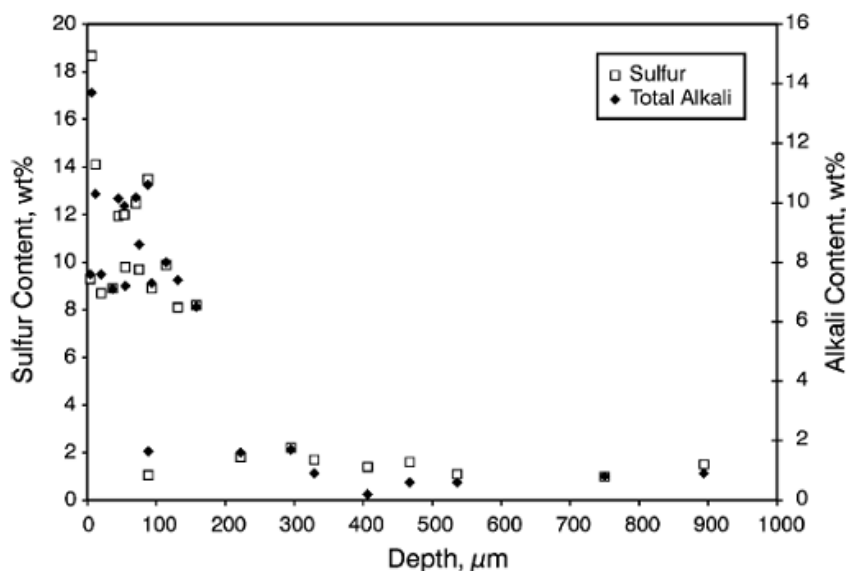
Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. A good catalyst must ensure high activity and selectivity for NO_x reduction and low activity in the oxidation of SO₂ to SO₄. Because of the high selectivity, the catalyst will have a specific temperature window at which the NO_x reduction is optimal (Granger 2007).

² See Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)

³ See Granger, P. Elsevier, "Past and Present in DeNO_x Catalysis: From Molecular Modeling to Chemical Engineering", (2007)

There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NO_x reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson⁴, alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.*, 2008, and Strege *et al.*, 2008). Figure 3 shows evidence of catalyst poisoning by both sulfur and alkalis⁵. The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NO_x control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NO_x reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst.

Figure 3: Sulfur and Alkali Penetration into the pores of the catalyst



Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

Figure 3 indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NO_x reduction (see Strege *et al.*, 2008).

⁴ See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)

⁵ See Strege, J. *et al.*, "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

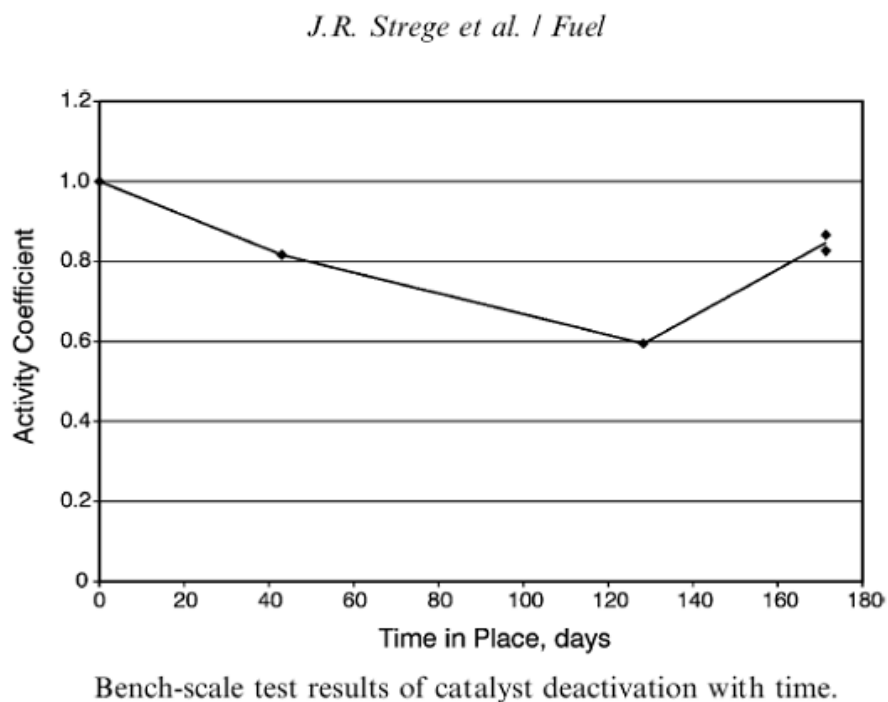
Figure 4: Bench Scale Test Results of Catalyst Deactivation over a Period of Time

Figure 4 provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NO_x conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro⁶, a good flow distribution is needed to ensure minimal ammonia slip. The potential for ammonia slip to create visibility impairment that is readily transported into nearby Great Sand Dunes National Park exists.

The state finds that a limited use - trial basis application of an SCR control technology on three kilns in Europe does not constitute “available” control technology for purposes of Reasonable Progress at the Holcim Portland Plant. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *“The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst.”* Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse.

⁶ See Barbaro, P.; Bianchini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be “available” for purposes of retrofitting such control technology on the Portland Plant. Reasonable Progress should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, given this fact and the difficulty that Holcim has had in obtaining viable vendor quotations for an SCR system, the Division has eliminated SCR as an available control technology for the Holcim Portland Plant for purposes of Reasonable Progress.

Step 2: Eliminate Technically Infeasible Options

As described above, water injection and SNCR were determined to be technically feasible and appropriate for reducing NO_x emissions from Portland cement kilns.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The design of the Holcim Portland Plant does allow for the effective use of SNCR, which requires ammonia-containing compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000°F) for reducing NO_x to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant.

The facility is currently permitted to emit 3,185.7 tpy of NO_x from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NO_x per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NO_x). The actual kiln NO_x emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NO_x per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NO_x. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NO_x per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NO_x control strategy has been well documented and recognized by EPA. A reduction in NO_x emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NO_x reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NO_x per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NO_x per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NO_x per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [$4.47/0.9 \times (1-0.45) = 2.73$]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [$3.64/0.9 \times (1-0.45) = 2.23$ lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NO_x limit.

Because SNCR is technically and economically feasible, the state did not further consider water injection because the levels of control associated with this option are not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NO _x Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NO _x Emissions (tpy)
Baseline NO _x Emissions	-	4.97	3,185.7 ¹
SNCR	45% ²	2.73	2,086.8

¹ Defaulted to the permit limit since the calculated baseline was higher.

² This is calculated based on the 50% SNCR removal efficiency and 10% bypass

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006. Holcim estimated that NO_x emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of \$1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues. Considering the concern with the ammonia slip, an overall SNCR removal efficiency of 45% was used in this analysis. This estimate was based on an installation cost of \$400,000 to \$600,000 and an annual cost of \$2,520,000. In February 2010, Holcim also provided a general direct capital investment cost estimate of \$700,000 to \$1,400,000 (excluding the capability for winter operations). The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant – Kiln System				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	(\$/yr)	(\$/ton)	(\$/ton)
Baseline NOx Emissions	-			
SNCR (45% control)	1,098.9	\$2,520,000 ¹	\$2,293	-

¹ Annualized cost is based on the estimates provided by Holcim. The state believes that the \$2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

Factor 2: Time Necessary for Compliance

It is anticipated that within five years or less after SIP approval, all the work necessary to study, design, construct and begin operating the SNCR system would be complete.

Factor 3: Energy and Non-Air Quality Impacts

SNCR systems do increase power needs to operate injection equipment, drive the pumps and fans necessary to supply reagents, and overcome additional pressure drops caused by the control equipment. Installing SNCR also increases levels of ammonia emissions, and can create a „blue plume“ if ammonia rates are not adequately controlled. Other environmental factors include the storage and transportation of the selected ammonia-based reagent. For SNCR systems, these types of energy and non-air quality impacts, while necessary to address, are not generally considered significant and do not adversely affect the selection of this technology.

Factor 4: Remaining Useful Life

The state is not aware of any near-term limitations on the useful life of the cement kiln system, so it can be assumed that it will remain in service for a 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO₂ emission rate of 99.17 lbs/hour, a NO_x emission rate of 837.96 pounds per hour (lbs/hour), and a PM₁₀ emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δ dv) at Great Sand Dunes National Park.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_x RP limitations. The following table lists the projected visibility improvements for these NO_x controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NO _x Control Method	98th Percentile Impact (Δ dv)	98th Percentile Improvement (Δ dv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NO _x , 586 lb/hr SO ₂ , 86.4 lb/hr PM ₁₀)	0.814	N/A
SNCR 45% overall NO _x control efficiency Limits of 2.73 lb/ton (30-day rolling average) and 2,086.8 tons per year (based on modeled emission rates of 750 lb/hr NO _x , 586 lb/hr SO ₂ , 86.4 lb/hr PM ₁₀)	0.526	0.288

Determination

For the kiln system, the state has determined that SNCR is the best NO_x control system available with NO_x RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_x reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

Summary of NO_x RP Determination for Kiln System

2.73 pounds of NO_x per ton of clinker (30-day rolling average)

2,086.8 tons of NO_x per year (12-month rolling total)

V. Reasonable Progress Evaluation of the Quarry and Finish Mill

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM₁₀ emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

Particulate Matter RP Determination for Quarry

The state has determined that the existing fugitive dust control plan and associated control measures which include: watering and the use of chemical stabilizers, compaction and re-vegetation of stockpiles, vehicle speed limitations, reclamation and sequential extraction of materials, paving, graveling and cleaning of haul roads, sequential blasting, wet drilling, and the suspension of activities during high wind events represent the most stringent control option for these types of emission sources. The existing fugitive dust control plan and the 47.9 tpy fugitive PM10 emission limit (12-month rolling total) for the quarry represent RP for PM10.

Summary of PM/PM10 RP Determination for Quarry

47.9 tons of fugitive PM10 per year (12-month rolling total)

Particulate Matter RP Determination for Finish Mill

The state has determined that the existing fabric filter baghouses and the existing emissions limits of 34.3 tpy of PM10 (12-month rolling total) for the finish mill represent the most stringent control option. Holcim has reported nominal control efficiency for the finish mill baghouses of 99.5%. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits represent RP for PM10 for the finish mill. In addition to the ton per year emission limit associated with this RP determination, the finish mill will also be subject to the recent changes to the PC MACT standard, which contains a visible emission limitation for finish mills.

Summary of PM/PM10 RP Determination for Finish Mill

34.3 tons of PM10 per year (12-month rolling total)

**Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Springs Utilities – Ray D. Nixon Power Plant**

I. Source Description

Owner/Operator:	Colorado Springs Utilities
Source Types:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas

The Nixon facility is located at 14020 Ray Nixon Road in Fountain, Colorado. This facility consists of one (1) steam driven turbine/generator unit, auxiliary boiler, the associated equipment needed for generating electricity, and two natural gas fired simple cycle combustion turbines driving electricity generators. The boiler fires low sulfur western coal as the primary fuel and can currently use No. 2 distillate oil or natural gas for an ignition fuel. The ignition fuels are used for startup of the boiler, flame stabilization, and the coal pulverizer startup. The facility also includes the various processes necessary to handle the coal, flyash and bottom ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control at appropriate point sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nixon power plant, and information about similar facilities to determine RP for NO_x, SO₂, and PM₁₀. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control¹."

These levels are as follows:

- NO_x – 40 tons per year

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

Nixon Power Plant is considered a single source with six (6) other facilities, depicted in Table 1.

Table 1: Facilities Co-Located or Considered to be a Single Source with Nixon Power Plant

Emission Sources	Colorado Construction/Operating Permit #	Permit Holder
Coal Screen	98PO149	Western Resources
2 Anaerobic Digestors, 4 Biogas Boilers and 2 Flares	96OPEP152	CSU – Clear Spring Ranch Solids & Handling
2 Natural Gas Turbines	99EP0851	Front Range Power Company, LLC
1 Coal-fired Boiler, 2 Natural Gas Turbines, Cooling Tower, Ash Handling, Coal Handling, Auxiliary Boiler	95OPEP106	CSU – Nixon Power Plant
Wastewater Treatment and 3 Internal Combustion Engines	95EP1097	CSU – Las Vegas Street Municipal Treatment Plant
Custom Anaerobic Wastewater Treatment System	03EP0158	CSU – Northern Water Reclamation Facility

The two natural-gas fired combustion turbines at Front Range Power Plant (FRPP) are above the Prevention of Significant Deterioration significance level for NO_x. The other single source facilities emit NO_x, SO₂, and/or PM₁₀ below the Prevention of Significant Deterioration significance levels.

The Front Range Power Plant (FRPP) is located at 6615 Generation Drive, Fountain, Colorado. The facility produces electrical power using two natural gas combustion turbines, with two Heat Recovery Steam Generators (HRSG), and duct burners. These two combustion turbines are evaluated within the source category “Combustion Turbines” in Section 8.2.3 of the Regional Haze SIP.

Nixon Unit 1 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. CSU provided information in “NO_x and SO₂ Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants” Submittal provided on February 20, 2009 and additional relevant information on February 21, March 21, May 10, and June 2, 2010. Table 2 depicts technical information for Nixon Unit 1.

Table 2: Nixon/FRPP RP-eligible Emission Controls and Reduction (%)

	Nixon Unit 1
Placed in Service	April 1980
Boiler Rating, MMBtu/Hr for coal	2,049
Electrical Power Rating, Gross Megawatts	227
Description	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing coal. The coal burner ignitors fire No. 2 fuel or spec oil & NG
Air Pollution Control Equipment	Western Precipitation Thermoflex Fabric Filter (baghouse)
Special Features	Low NO _x burners placed in service in 1989
Emissions Reduction (%)	NO _x – 37% SO ₂ – None PM/PM ₁₀ – 99.9/99.7%

Regulations that apply to the boiler are as follows:

For Nixon Unit 1:

- NSPS Subpart D regulates particulate matter emissions to 0.1 lb/MMBtu.
- NSPS Subpart D regulates NO_x emissions to 0.7 lb/MMBtu.
- The Title V Operating Permit limits annual NO_x emissions to 2853.3 tons per year.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program regulates NO_x emissions to 0.50 lb/MMBtu of heat input on an annual average basis.
- NSPS Subpart D regulates SO₂ emissions to 1.2 lb/MMBtu.

II. Source Emissions

Table 3 summarizes each unit at the facility and applicable NO_x, SO₂, and PM actual emissions averaged over the 2006 – 2008 timeframe with data from EPA's CAMD database, Colorado's Air Pollutant Emission Notices submitted by the facility, and Colorado inspection reports as applicable. Table 4 summarizes the NO_x, SO₂, and PM actual emissions averaged over the 2006 – 2008 timeframe (baseline) for each RP-eligible unit.

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit - Nixon Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Boiler #1	SO ₂ (tons)	3877.6	4043.1	4442.3	4121.0
	SO ₂ (lb/MMBtu)	0.46	0.52	0.53	0.50
	NO _x (tons)	2390.1	2137.0	2542.9	2356.7
	NO _x (lb/MMBtu)	0.26	0.26	0.26	0.26

Colorado Department of Public Health and Environment - Air Pollution Control Division

	PM ₁₀ (tons)	89.24	82.29	88.78	86.8
	PM ₁₀ (lb/MMBtu)	0.011	0.011	0.011	0.011
<i>Auxiliary Boiler</i>	SO ₂ (tons)	0	0	0	0.0
	SO ₂ (lb/MMBtu)	0.00	0.00	0.00	0.00
	NO _x (tons)	0.02	0.02	0.05	0.0
	NO _x (lb/MMBtu)	1.50	1.50	1.52	1.51
	PM ₁₀ (tons)	0	0	0	0.0
	PM ₁₀ (lb/MMBtu)	0.000	0.000	0.000	0.000
<i>Nixon Combustion Turbine 1</i>	SO ₂ (tons)	0.01	0.01	0.01	0.0
	SO ₂ (lb/MMBtu)	0.00	0.00	0.00	0.00
	NO _x (tons)	0.81	0.61	0.76	0.7
	NO _x (lb/MMBtu)	0.04	0.04	0.04	0.04
	PM ₁₀ (tons)	0.23	0.19	0.25	0.2
	PM ₁₀ (lb/MMBtu)	0.011	0.012	0.012	0.012
<i>Nixon Combustion Turbine 2</i>	SO ₂ (tons)	0.01	0.02	0.01	0.0
	SO ₂ (lb/MMBtu)	0.00	0.00	0.00	0.00
	NO _x (tons)	0.97	1.67	0.85	1.2
	NO _x (lb/MMBtu)	0.04	0.05	0.05	0.05
	PM ₁₀ (tons)	0.27	0.36	0.23	0.3
	PM ₁₀ (lb/MMBtu)	0.012	0.012	0.014	0.012
Coal Reclaim Conveyor (003)	PM ₁₀ (tons)	25.97	25.97	21.85	24.60
Ash Handling/Disposal (006)	PM ₁₀ (tons)	1.41	1.41	1.41	1.41
Coal Handling (008)	PM ₁₀ (tons)	23.2	23.2	1.47	15.96
Ash Haul Roads & Disposal (009)	PM ₁₀ (tons)	1.85	1.85	1.87	1.86
Unit #1 Cooling Tower	PM ₁₀ (tons)	0.8	0.8	0.75	0.78
Four Digester Gas Boilers	SO ₂ (tons)	10.15	9.03	9.03	9.40
	NO _x (tons)	4.95	3.84	3.84	4.21
	PM ₁₀ (tons)	0.50	0.35	0.35	0.40
2 Digester Gas Flares	SO ₂ (tons)	11.0	11.19	11.19	11.13
	NO _x (tons)	2.61	2.65	2.65	2.64
	PM ₁₀ (tons)	0.54	0.40	0.40	0.45
Sludge Injection & Unpaved Roads	PM ₁₀ (tons)	8.90	8.90	8.90	8.90

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day NO_x rolling average is likely about 0.58 lbs/MMBtu for Boiler 1).

Units *italicized* in Table 2 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Table 4. Nixon Unit 1 Baseline Emissions

Pollutant	Nixon Unit 1	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO _x	2,357	0.258
SO ₂	4,121	0.453
PM ₁₀	87	0.002***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO₂ emissions and for PM₁₀ emissions for the turbines.

***The PM₁₀ emission rate is determined from the Title V permit compliance stack test. These values are as follows: Nixon Unit 1 – 0.0021 lb/MMBtu (4/15/2008)

III. Units Evaluated for Control

As documented by CSU, Nixon Unit 1 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2007 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nixon Unit 1	8,752	0.22	4.99

Table 1 lists the units at Nixon that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Nixon Unit 1

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Nixon Unit 1 ²	NO _x	7.2
	SO ₂	35 x %S = 7.7*
	PM/PM ₁₀	PM – 49.90** PM ₁₀ – 11.48

*%S = % of sulfur present in coal supply. For example, 35 x 0.22 = 7.7

**%A = % of ash present in coal supply. For example, 10 x 4.99 = 49.90

IV. Reasonable Progress Evaluation of Nixon Unit 1

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CSU identified one SO₂ control option:

Flue gas desulfurization (FGD):

Lime spray dry absorber (SDA or dry FGD)

The Division identified two additional SO₂ control options:

Flue gas desulfurization (FGD):

Lime or limestone-based (wet FGD)

Dry sorbent injection – Trona (DSI)

² EPA AP-42 Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.
<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants³. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

CSU’s 2009 submittal states that a dry FGD (SDA) system is technically feasible. The Division concurs with this conclusion.

The Division notes that traditional wet FGD controls are possible at Nixon Unit 1 considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls at Nixon Unit 1.

It is worth noting that CSU is currently testing a new, innovative non-traditional wet scrubber control system at another facility that appears to be as effective, if not more effective, at controlling SO₂ emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system,

³ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

⁴ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4.

Although the technology being tested by CSU does not technically meet the definition of “available” as set forth in the BART (Regional Haze) rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber at Nixon Unit 1 if desired and applicable. This process will be required to meet the emission limits established for the LSD technology established in this RP determination. Regardless of the technology utilized, Nixon has to meet the LSD-based RP limits within 5 years of EPA approval of the Regional Haze SIP. CSU will test the NeuStream system at this facility until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO₂ RP limit for Nixon Unit 1.

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO₂ present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler’s particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU’s preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO₂ which has a reddish-brown color. This conversion of NO to NO₂ can create a brown plume from the stack which could create

opacity compliance issues. Due to variability of boiler configurations, coal composition, NO_x to SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO₂ removal at another facility. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ removal real-time testing. Therefore, since CSU notes that DSI is technically feasible for a similar facility, the Division assumes this same technology is also then technically feasible for Nixon Unit 1.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Unit 1 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO₂ determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Dry FGD (LSD): Controlling SO₂ Emissions: A Review of Technologies⁵ indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Nixon Power Plant, typically <0.5% as detailed in Table 5, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Therefore, dry FGD is evaluated at two control efficiencies level – 78% (0.010 lb/MMBtu annual average) and 82.3% (0.08 lb/MMBtu annual average) for comparison purposes.

DSI: Based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved to be 60% SO₂ removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

⁵ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Table 7 summarizes each available technology and technical feasibility for SO₂ control.

Table 7: Nixon Unit 1 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	75 – 85%	Y
DSI	60% (CSU)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

LSD/DSI: CSU submitted cost estimates for a LSD system on Unit 1 on February 20, 2009. CSU provided cost estimates for the DSI system evaluated on another similar Colorado unit (CSU Drake Unit 5) on May 10, 2010.

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in Table 8. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO₂ when measured on a per MW-h basis. These estimates are for another facility, Drake Units 6 and 7, but are assumed to be directly applicable to Nixon Unit 1 as well.

Table 8: LSD Energy Replacement Costs

Unit	Replacement capacity cost (\$/kW-yr)	Differential energy cost (\$/MW-h)
Drake 6/7	44	35

This information, including detailed capital and annual cost data, are provided as “CSU Drake BART Submittals” and “CSU Nixon RP Submittals”. CSU originally generated costs using EPRI’s FGD Cost model for Drake.⁶ This model uses specific unit data to

⁶ EPA’s BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO₂ removal equipment as of

calculate the cost of controlling emissions, and is considered to be accurate within $\pm 30\%$. When preparing cost estimates for Nixon, cost estimates were developed using the IECCOST program.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,⁷ shown in Table 9.

Table 9: CSU-Drake SO₂ LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group (\$/ton SO ₂ Removed)	CSU Refined Cost Estimate (\$/ton SO ₂ Removed (Control System))	Cost Differential
Drake Unit 6 – 85 MW	\$2,399	\$2,579 - \$2,981	+ 8% – 24%
Drake Unit 7 – 142 MW	\$1,796	\$2,140 - \$2,694	+ 19% - 50%
Nixon Unit 1 – 225 MW	\$1,282	\$3,744 - \$3,950	+ 192% - 208%

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Unit 1 using various cost updates from the 2008 timeframe. Nixon has reflected the costs of retrofitting a facility that is moderately congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. The Division does not necessarily concur with these estimates, but will accept them for purposes of this RP analysis.

CSU only submitted DSI cost information for another facility, Drake Unit 5. The Division scaled this cost information for Units 1 in Table 10. Please see "Drake APCD Technical Analysis" and "Nixon APCD Technical Analysis" for more details.

the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

⁷ EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO₂ Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

For dry FGD, CSU estimated a removal rate of 80% based on 2008 average data and a resulting emission rate at the BART presumptive limits of 0.10 lb/MMBtu. The Division adjusted this removal rate using the baseline SO₂ emissions from Table 4 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 78 - 82% that meets the BART presumptive limit for Nixon Unit 1. This range allows the Division to determine the most reasonable RP limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See “Nixon APCD Technical Analysis” for more details.

Table 10 illustrates resultant SO₂ emissions for each technically feasible control option. Table 11 shows the SO₂ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 4. The Division analyzed both annual and 30-day rolling average limits. The Department’s experience with power plants suggests that the maximum 30-day rolling average SO₂ emission rate is approximately 5% higher than the annual average emission rate.

Table 10: Nixon Unit 1 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 1		
		(tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	4,121	0.453	
DSI	60	1,649	0.181	0.190
Dry FGD (LSD) @ 78% control	78	907	0.100	0.105
Dry FGD (LSD) @ 82.3% control	82.3	729	0.080	0.084

Table 11: Nixon Unit 1 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
DSI	2,473	\$4,938,692	\$1,997	\$1,997
Dry FGD (LSD) @ 78% control	3,215	\$12,036,604	\$3,744	\$9,568
Dry FGD (LSD) @ 82.3% control	3,392	\$13,399,590	\$3,950	\$7,691

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals⁸, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or “first in time - first in right,” and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado’s domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO₂ control technology consideration on commercially available once-through dry FGD controls, specifically, “lime spray dryers” (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO₂ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO₂ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO₂ emission reduction benefits (tons of SO₂ reduced annually) and visibility improvement (deciview improvement at nearest Class I

⁸Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. “Black Hills Clark Station NO_x Reduction Feasibility Study.” Pgs. 3-13 and 3-14.

area) when compared to LSD or the pilot NeuStream-S FGD scrubber when applied to the Nixon Unit 1 boiler.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water, as detailed in Table 12. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.⁹

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
Drake 6	68	35.7
Drake 7	100	53.0
Nixon 1 (scaled)	~160	~84.0

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,¹⁰ which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality

⁹ 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

¹⁰ Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon Unit 1 in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO₂ emission rates to determine control efficiencies and annual reductions.

Table 13: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO ₂ Control Scenario	Unit(s)	Class I Area Affected	3-year totals			3-year totals		
			Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO ₂ rates	1	RMNP	17	---	---	6	---	---
DSI @ 0.18 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.10 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.08 lb/MMBtu	1		17	6	11	6	1	5

Table 14: Visibility Results – SO₂ Control Scenarios

SO ₂ Control Scenario	Unit(s)	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	(\$/deciview)
Max 24-hr SO ₂ rates	1	0.914			---
DSI @ 0.18 lb/MMBtu	1	0.48	0.44	48%	\$11,249,869

LSD @ 0.10 lb/MMBtu	1	0.46*	0.46	50%	\$26,454,076
LSD @ 0.070 lb/MMBtu	1	0.42	0.50	55%	\$28,307,522

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Nixon Modeling Summary” for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ RP the following SO₂ emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi-dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO₂ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: \$3,744 per ton SO₂ removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM₁₀)

Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/PM₁₀ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP106 Condition 1.5.5 requires Unit 1 to conduct performance testing for PM₁₀ annually. While the emission limit in Condition 1.5.1 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 15 shows the most recent stack test data (April 14, 2008). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: Nixon Unit 1 2008 Stack Test Results

Pollutant	Unit 1 (lb/MMBtu)
Filterable PM ₁₀	0.0021
PM ₁₀ Control efficiency	99.5%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control options. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limits are RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM₁₀ is not needed for Nixon Unit 1.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Ultra-low NO_x burners and Over-fire air (ULNBs+OFA)
- Selective Non-Catalytic Reduction (SNCR)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load¹¹. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Unit 1. Since ROFA® technology would not be expected to

¹¹ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Unit 1. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N₂ rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed¹². The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Unit 1.

ULNBs: Unit 1 has low NO_x burners installed, shown in Table 2. These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Unit 1.

ULNBs+OFA: Since ULNBs and OFA are each technically feasible options and would be installed separately for Unit 1, it stands to reason that ULNBs+OFA is a technically feasible options for Unit 1.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

¹² IEA Clean Coal Centre: Clean Coal Technologies – Air Staging for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU Nixon, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 1 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Nixon Unit 1.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Nixon Unit 1. This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for Nixon Unit 1.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler¹³ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers¹⁴ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Nixon Unit 1.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have

¹³ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

¹⁴ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's RP analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost (\$/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule, and therefore should be ruled out for RP as well. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a technically feasible alternative for Nixon Unit 1. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu¹⁵. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,¹⁶ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nixon Unit 1 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 25% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with

¹⁵ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

¹⁶ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

OFA controlling 40 – 60% of NO_x emissions.¹⁷ The low NO_x burners currently achieve about 10% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.¹⁸ Therefore, the Division concurs with CSU's additional 25% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at Nixon Unit 1. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.¹⁹ Therefore, the Division concurs with CSU NO_x reduction estimates for ULNBs.

ULNBs+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. ULNBs alone can achieve 20% control; OFA alone can achieve 25% control. When determining the appropriate control efficiency regarding the combination of ULNBs and OFA, the most important consideration to note is that Nixon burns only Power River Basin (PRB) coal which is low in nitrogen content initially, so the margin to reduce NO_x is lower than other facilities (i.e. Drake). The Division and CSU concur that a realistic control efficiency assumption is 30% for Nixon Unit 1.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study²⁰ to conservatively approximate that Nixon Unit 1 can achieve 30% control when SNCR is applied.

SCR: CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2008 baseline emissions (or 0.05 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions and adjusted the resultant SCR percent removal to 73% (or 0.07 lb/MMBtu), which the Division considers more realistic and consistent with other Colorado facility submittals. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80

¹⁷ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹⁸ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

¹⁹ U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory.

<http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf>

²⁰ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

– 90% reduction.^{21,22} However, in the Division’s experience a emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: Nixon Unit 1 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners (LNB)	~10%	Y – installed
LNB + OFA	60 – 81%	Y (partially installed)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO _x burners (ULNBs)	20%	Y
ULNBs+OFA	30%	Y
Selective non-catalytic reduction (SNCR)	20 – 40%	Y
Selective catalytic reduction (SCR)	70 – 90%	Y
ULNB/SCR layered approach	70 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake and Nixon boilers in 2004. The cost estimates were generated using EPRI’s IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled “NO_x

²¹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

²² Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Controls for Existing Utility Boilers,”²³ OFA alone ranges from \$410 - \$1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Nixon’s estimated OFA NO_x reductions (25%). The estimates in Table 17 and Table 18 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU’s cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 18. The Division considers CSU’s estimated costs more than reasonable, with ULNBs at about \$1,200/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.^{24, 25}

ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.²⁶ A similar Colorado facility estimated operating expenses at approximately 81 – 86%.²⁷ Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.²⁸

²³ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁴ Amar, Praveen, 2000. “Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness.” Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/nox-2000.pdf

²⁵ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁶ ICAC, 2000. Institute of Clean Air Companies, Inc. “White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions.” Washington, D.C. 2000.

²⁷ CENC, 2009. “NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado.” Prepared by AECOM.

²⁸ EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.” <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

The Division used information from a similar facility submittal to determine approximate SNCR costs scaled for the Nixon boiler since CSU did not have SNCR information.²⁹ The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Nixon boiler in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 1 is approximately \$4,500 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{30,31} EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.³² Although the resulting cost estimates for the Nixon boiler greater than these ranges, the smaller size of the boiler as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing \$2,600 - \$7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{33,34} The SCR system estimates for the CSU Nixon boiler is approximately \$6,400, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 17 illustrates resultant NO_x emissions for each technically feasible control option. Table 18 shows the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for

²⁹ CENC, 2009. "NO_x Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

³⁰ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³¹ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

³² EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

³³ Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." <http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³⁴ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

tons of NO_x reduced per year. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 17: Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 1		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling (lb/MMBtu)
Baseline	---	2,357	0.258	
Ultra-low NO _x burners (ULNBs)	20	1,885	0.206	0.24
Overfire air (OFA)	25	1,768	0.194	0.22
ULNBs+OFA	30	1,650	0.181	0.21
Selective Non-Catalytic Reduction (SNCR)	30	1,650	0.181	0.21
ULNB+SCR	73	636	0.070	0.080
Selective Catalytic Reduction (SCR)	73	636	0.070	0.080

Table 18: Unit 1 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Ultra-low NO _x burners (ULNBs)	471	\$567,000	\$1,203	\$1,203
Overfire air (OFA)	589	\$403,000	\$684	(\$1,392)
ULNBs+OFA	707	\$907,000	\$1,372	\$4,812
Selective Non-Catalytic Reduction (SNCR)	707	\$3,226,877	\$4,564	---
ULNB+SCR	1,720.4	\$11,007,000	\$6,398	\$7,677
Selective Catalytic Reduction (SCR)	1,720	\$11,010,000	\$6,400	---

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals³⁵, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and

³⁵ Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NO_x Reduction Feasibility Study." Pgs. 3-13 and 3-14

shutdown, after SIP approval, it would take CSU be approximately 2-3 years for SNCR and 3-4 years for SCR. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a aqueous ammonia reagent versus an ammonia reagent.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon 1 is in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Table 19: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Unit(s)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
			Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour NOx rates	1	RMNP	17	---	---	6	---	---
ULNBs @ 0.21 lb/MMBtu	1		17	15	2	6	4	2
OFA @ 0.19 lb/MMBtu	1		17	15	2	6	4	2
ULNBs+OFA @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SNCR @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SCR @ 0.07 lb/MMBtu	1		17	12	5	6	3	3

Table 20: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Unit(s)	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	(\$/deciview)
Max 24-hour NOx rates	1	0.91	---	---	---
ULNBs @ 0.21 lb/MMBtu	1	0.77	0.15	16%	\$3,831,081
OFA @ 0.19 lb/MMBtu	1	0.76*	0.15	17%	\$2,616,883

ULNBs+OFA @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	\$6,024,845
SNCR @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	\$20,042,714
SCR @ 0.07 lb/MMBtu	1	0.68	0.24	26%	\$46,639,831

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Nixon Modeling Summary” for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Nixon Unit 1 the following NOx emission rate:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that ultra-low NOx burners with over-fire air is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

V. RP Evaluation for Fugitive Dust Sources: Coal Reclaim Conveyor (003) and Coal Handling (008)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 95OPEP106.

Coal handling is comprised of five (6) parts – reclaim tunnel bagfilter vent, coal crusher building bagfilter vent, coal gallery bagfilter vents, and coal train off-loading-conveying-stockpiling. It should be noted that while these two sources are reported individually in Colorado’s emission inventory, in the Operating Permit, these sources are combined together since coal handling is treated as one point. Colorado Regulation No.1.II.A.1 limits opacity from these sources to 20%. This source is also subject to NSPS Subpart Y, New Source Performance Standards for Coal Preparation Plants. Additionally, the following measures to control fugitive dust via a fugitive particulate emissions control plan (Condition 3.4):

- A wet dust suppression system shall be used for railroad car unloading.
- Above ground conveyors to and from the transfer building must be covered.
- Loadout to storage must by telescoping chute.
- Emissions from coal storage piles shall be effectively controlled by application of chemical binders and by watering, if need be.

These existing controls and corresponding emission limits in Section II, Condition 3 of Operating Permit 95OPEP106 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Nucla Station**

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100218
Boiler Type:	Atmospheric Circulating Fluidized Bed

The Tri-State Generation Transmission & Association, Inc. (Tri-State) Nucla Station is located in Montrose County approximately 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and limestone injection into the fluidized bed for the removal of sulfur dioxide (SO₂). The boiler is designed for the reduction of NO_x formation and a small Selective Non-Catalytic Reduction (SNCR) system using anhydrous ammonia injection is used for NO_x trim to ensure compliance with annual NO_x limits. Additionally, the facility includes a number of fugitive dust sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nucla facility, and information about similar facilities to determine RP for PM and SO₂. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control¹."

¹ Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

These *de minimis* levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

The Nucla facility originally consisted of three coal fired stoker boilers that were shut down and replaced with an atmospheric circulating fluidized bed (CFB) boiler (Unit #4). Unit #4 was placed in service in June, 1987. CFBs without post-combustion controls are able to achieve emission rates of NO_x and SO₂ that are lower than Pulverized Coal (PC) fired boilers due to the nature of their design (lower combustion temperatures result in less NO_x formation, while intimate mixing of a sorbent within the fluidized bed results in enhanced SO₂ removal). SO₂ emissions from CFBs without post-combustion controls are typically lower than similarly sized PC-fired boilers equipped with Flue Gas Desulfurization (FGD) systems.² The original construction of Unit #4 included four baghouses for the control of PM₁₀ emissions, limestone injection to the combustion chamber for SO₂ removal, and inherent minimization of NO_x emissions due to boiler design.

In 2006, Tri-State permitted and installed a small-scale SNCR system that injects anhydrous ammonia to provide additional NO_x reduction. Tri-State does not operate the SNCR system frequently; it is used on occasions when NO_x emissions approach 0.4 lb/MMBtu (operation above this level at high unit capacity factors results in levels that approach the annual NO_x limit of 1,987.9 tons per year on a 12-month rolling basis). The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour.³

Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, and July 30, 2010. Table 1 depicts technical information for Unit 4 at Nucla Station.

Table 1: Nucla Unit 4 Technical Information

	Unit 4
Placed in Service	1987
Gross Boiler Rating, MMBtu/Hr for coal	1,112
Electrical Power Rating, Net Megawatts	110
Description	Pyropower Circulating Fluidized Bed, Coal Fired Boiler

² Babcock & Wilcox Company, 2000. “Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power” Presented to POWER-GEN Asia 2000. Page 2.

³ Tri-State, May 14, 2010. “RE: Response to the Division’s January 25, 2010 Letter Regarding NO_x Emissions Control Costs.” Page 6.

Air Pollution Control Equipment	PM/PM ₁₀ – Fabric Filter Baghouses (1987) NO _x – Voluntary SNCR (2006) SO ₂ – Limestone Injection (1987)
Emissions Reduction (%)	NO _x – NA ⁴ SO ₂ – 77.4% PM/PM ₁₀ – 98% - 99.9+ ⁵

II. Source Emissions

Table 2 summarizes the NO_x and SO₂ actual emissions averaged over the 2006 – 2008 timeframe from EPA’s CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado’s Air Pollutant Emission Notices (APENs) submitted by the facility (based on amount and heat content and amount of coal combusted, also as reported on the APENs).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Tri-State Nucla Station

NO _x (tons/year)	SO ₂ (tons/year)	PM ₁₀ (tons/year)
1,760	1,335	40

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Tri-State Nucla Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 4 Boiler	SO ₂ (tons)	1509.4	1230.4	1265.7	1335.2
	SO ₂ (lb/MMBtu)	0.34	0.30	0.30	0.31
	NO _x (tons)	1716.0	1598.0	1711.4	1675.1
	NO _x (lb/MMBtu)	0.39	0.38	0.40	0.39
	PM ₁₀ (tons)	41.6	39.4	40.24	40.4
	PM ₁₀ (lb/ MMBtu)	0.009	0.009	0.009	0.009
<i>Coal Handling & Processing</i>	<i>PM₁₀ (tons)</i>	<i>2.09</i>	<i>2.15</i>	<i>2.15</i>	<i>2.13</i>
<i>Ash Handling & Processing</i>	<i>PM₁₀ (tons)</i>	<i>8.91</i>	<i>10.62</i>	<i>10.62</i>	<i>10.05</i>
P401 Cooling Tower	PM ₁₀ (tons)	37.5	23.7	0.34	20.5
P402 Cooling Tower	PM ₁₀ (tons)	9.8	9.8	9.8	9.8
Limestone Preparation	PM ₁₀ (tons)	1.29	1.29	1.29	1.29

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

⁴ NO_x emission reductions from the existing SNCR system have not been characterized because the system is operated only infrequently – total reported emissions are therefore assumed to be uncontrolled.

⁵ The low range is calculated assuming uncontrolled emissions based on AP-42 factors. The high range is stated in the U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf. Page 5.

Note also that Tri-State installed improved drift eliminators on the P401 Cooling Tower in 2007. The Operating Permit⁶ for the facility includes a limit of 0.55 tons PM₁₀ per year effective beginning October 1, 2007 (actual emissions for 2008 were reported to be 0.34 tons per year); therefore this unit will also not be considered further in this analysis.

The Title V permit includes the following limits for the Unit 4 Boiler:

- NO_x: 0.50 lbs/MMBtu on a rolling 30-day average (PSD limit), 0.5 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da) and 1987.9 tons per year on a rolling 12-month total
- SO₂: 1.2 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da), 1.2 lb/MMBtu on a 3-hr average (Colorado Regulation No. 1), 0.4 lb/MMBtu on a 30-day average (Colorado Regulation No. 6) and 1598.9 tons per year on a rolling 12-month total; 70% reduction at less than 0.6 lb/MMBtu (30-day rolling average)
- PM₁₀: 131 tons per year on a rolling 12-month total
- PM: 0.03 lb/MMBtu (PSD limit), 0.03 lb/MMBtu (NSPS Subpart Da) 0.1 lb/MMBtu (Colorado Regulation No. 1) and 135.9 tons per year on a rolling 12-month total

III. Units Evaluated for Control

The Nucla boiler burns Colorado bituminous coal. Nucla Station is a mine-mouth facility; therefore the Division assumes that this facility burns New Horizon Coal, since that facility is the closest coal mine identifiable in Division records. The actual APEN coal specifications (2006 – 2008) are listed below in Table 4. Uncontrolled emission factors are outlined in Table 5.

Table 4: Coal Specifications (2006 - 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nucla Unit 4	10,545	0.83	19.95

Table 5: Uncontrolled emission factors for Nucla RP-eligible sources⁷

Emission Unit	Pollutant			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Unit 4 (lb/ton)	5.0	25.8	17.0	12.4
Unit 4 (lb/MMBtu)	0.24	1.22	0.81	0.59

⁶ Colorado Air Pollution Control Division, September 25, 2007. Colorado Operating Permit 96OPMO168: Nucla Station. Section II: Condition 8.2, Page 38.

⁷ PM and PM₁₀ emission factors are from AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf> (for spreader stokers with multiple cyclones and reinjection). Uncontrolled SO₂ emission factors are based on the AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1 emission factor for underfeed stoker boilers (Table 1.1-3). Uncontrolled NO_x emission factors are based on actual emissions from 2006 – 2008.

IV. Reasonable Progress Evaluation of Unit 4

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

The Division identified all of the available CFB control technologies listed below.

Fuel Switching – Natural Gas or Alternate Coal Source

Fuel Washing

Limestone Injection Process Upgrades

Post-Combustion Controls: Dry Scrubbing (Spray Dry Absorber, Circulating Dry Scrubber, Hydrated Ash Reinjection and Dry Sorbent Injection)

Post-Combustion Controls: Wet Scrubbing

As discussed in EPA's BART Guidelines⁸, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the existing limestone injection process if technically feasible.

The current PSD permit SO₂ limits are depicted in Table 6.

Table 6: Nucla Unit 4 SO₂ PSD Permit Limits

	SO ₂ limits (lb/MMBtu)			Rolling 12-month Emission Limit (tons/year)
	3-hour avg. (Colo. Reg. No. 1)	Rolling 30-day avg. (NSPS Subpart Da)	30-day avg. (Colo. Reg. No. 6)	
Unit 4	1.2	1.2	0.4	1,599

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Alternative Coal Sources: CFB boilers are designed to create a circulating bed of solid fuels; the nature and locations of the solids and air injection points as well as the combustion zone itself are inherently different from traditional PC and natural gas-fired boilers. The recent conversion from a natural gas-fired boiler to a CFB-boiler at the Lamar Light and Power facility in Lamar, Colorado required the construction of an entirely new and separate unit. Therefore, the Division determines that the conversion to natural gas is technically infeasible for Nucla's CFB boiler.

Nucla Unit #4 is currently burning coal from the New Horizon Mine located five miles south of the plant, with an average sulfur content of 0.83%. The facility is located approximately 4.5 miles southeast of Nucla, Colorado and does not have rail service. There are no other coal mines located 100 miles of the facility. Because the current coal source is already lower than 1% sulfur and no other sources within a reasonable distance of the facility have been identified, fuel switching to other coal types will not be considered further in this analysis.

⁸ EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs 39133.

Fuel Washing: Fuel washing has been used historically to reduce the sulfur content of some high sulfur coals prior to combustion. There are no identified fuel-washing processes for low sulfur coal.

Existing Process Upgrades and Post-Combustion Controls: In the absence of any specific feasibility or cost information related to SO₂ controls for the Nucla Station, the Division relied on control evaluations performed for other CFB boilers, with a focus on CFB boilers in the western part of the country. Coal supplies for CFB boilers in the eastern part of the country are significantly different from western coals in terms of sulfur and heat content; therefore the Division believes that the specifics of control devices for eastern CFB boilers may not be wholly applicable to Nucla Unit 4. The majority of recent BACT determinations identify limestone injection, with or without additional post-combustion controls as the chosen SO₂ control device. Refer to “Division RBLC Analysis” for more details. The Division reviewed two of the most recent BACT analysis reports in detail: the lignite-fired Spiritwood Station in North Dakota⁹ and the waste coal-fired Bonanza Station in Utah¹⁰. The Spiritwood Station was intended to fire beneficiated lignite but is designed with the capability for firing dried lignite and subbituminous coal as well, and the BACT analysis specifically identified the findings to be applicable to subbituminous coal. The estimated control efficiencies and costs from these reports were used as a basis to evaluate potential SO₂ emission control options at Nucla.

Limestone Injection Process Upgrades: The average reduction in SO₂ emissions due to limestone injection into the CFB boiler for the baseline period is estimated to be 77.4% as shown in Table 1, above. The unit participated in a U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) from 1988 – 1991 in order to examine the energy and environmental impacts from the unit, which was the first utility-scale atmospheric CFB boiler at the time. The project demonstrated a 70% SO₂ removal rate at a calcium to sulfur ratio (Ca/S) of 1.5 and a 95% removal rate at a calcium to sulfur ratio of 4.0¹¹. The demonstration project tested a range of western bituminous coals, including Salt Creek (0.5% sulfur), Peabody (0.7% sulfur) and Dorchester (1.5% Sulfur), with the Salt Creek coal serving as the baseline coal (used in 62 of the 72 tests). Limestone injection process upgrades are feasible for Nucla Unit 4.

Post-Combustion Controls – Dry Scrubbing: Additional treatment of the boiler exhaust gases can potentially be accomplished with several dry scrubbing techniques.

⁹ Barr, July 2007. “Application for a Permit to Construct a Combined Heat and Power (CHP) Plant.” Prepared for Great River Energy – Spiritwood Station, Spiritwood, ND.

¹⁰ EPA, August 30, 2007. “Deseret Power Electric Cooperative, Bonanza Power Plant, Waste Coal Fired Unit: Prevention of Significant Deterioration Permit to Construct – Final Statement of Basis for Permit No. PSD-00-0002.01.00. ”

¹¹ U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project.
http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf

Spray Dryer Absorption (SDA) is the most commonly used follow-on controls for CFB boilers with limestone injection. SDAs currently make up about 12% of Flue Gas Desulfurization (FGD) systems at U.S. power plants¹². SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system captures SO₂ by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and the collected in a particulate control device. A SDA system is technically feasible for Nucla Unit 4.

Circulating Dry Scrubber (CDS) Systems use a circulating fluidized bed of dry hydrated lime in a separate reactor tower. The flue gas must first be humidified with a water mist. EPA noted in the Bonanza BACT analysis that CDS systems have limited application on large PC-fired boilers or CFB boilers, and can result in particulate loading rates that are high enough to create unacceptable pressure drops across fabric filters and therefore require electrostatic precipitators for particulate control.¹³ The potential need to replace the existing baghouse (99.9% particulate control) with an electrostatic precipitator renders a CDS system inappropriate as an option for the Nucla station.

Hydrated Ash Reinjection (HAR) increases utilization of uncreated calcium oxide in the CFB boiler ash by collecting, hydrating and re-introducing a portion of the unit's ash in a separate vessel prior to the baghouse. HAR is technically feasible for Nucla Unit 4.

Dry Sorbent Injection (DSI) systems require injection of powdered absorbent directly into the flue gas stream. EPA identified this option as impractical for use in a CFB boiler burning low sulfur coals due to an expected SO₂ reduction of less than 50%.¹⁴ DSI is a technically feasible option for Nucla.

Post-Combustion Controls – Wet Scrubbing: Wet Flue Gas Desulfurization (FGD) systems were identified as potentially feasible for CFB boilers in both the Bonanza and Spiritwood BACT analyses. The process involves an alkaline slurry (lime or limestone) scrubbing liquid in an absorber tower. The process produces a wet byproduct that requires dewatering. Wet scrubbing is a technically feasible option for Nucla Unit 4.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Limestone Injection Process Upgrades: The Spiritwood BACT analysis states that the control efficiency from the limestone injection process is expected to be 75%¹⁵ (further reductions occur in a Spray Dry Absorber). EPA acknowledges in the Bonanza BACT analysis report that a control efficiency of 80 – 85% should be expected for the limestone injection process alone¹⁶.

¹² Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environment Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg V.

¹³ Ibid., Page 92.

¹⁴ EPA, Deseret Power Electric Cooperative...Page 93.

¹⁵ Barr, Appendix E, Page 50

¹⁶ EPA, Deseret Power Electric Cooperative...Page 99.

The Division believes that an expectation of 95% reduction for the Nucla station from the limestone injection process, although it may have been demonstrated during the CCTDP test project, is not appropriate as a long term operation scenario. The fluidized bed is currently optimized carefully to balance efficiency, operational and emission characteristics. Increasing the Ca/S to 4.0 in order to achieve 95% SO₂ reduction is expected to cause significant operational issues; the Division has not found any evidence of current CFB boilers in operation with Ca/S ratios near 4.0. Higher limestone injections will also result in an increase in NO_x emissions, although the quantitative relationship is not well understood.¹⁷ For these reasons, the Division believes that an increase in SO₂ control efficiency to 85% by increasing limestone injection is a feasible option. This correlates to an approximate 39.4% decrease in comparison to current SO₂ emissions.

Spray Dry Absorber: Based on experience with other Colorado EGUs, the Division believes that a realistic achievable control efficiency for a SDA at Nucla is approximately 87%, or an approximate 0.04 lb/MMBtu (30-day rolling average). This is approximately 97% from uncontrolled SO₂ emissions. A review of the EPA's RBLC database showed two retrofit Western facilities from about 0.04 – 0.05 lb/MMBtu (30-day rolling average) with SDAs as the SO₂ control option. Please refer to the document "RBLC for CFBs – July 2010" for more information.

Limestone Injection Improvements + Spray Dry Absorber: Limestone injection improvements (85%) combined with a spray dry absorber (90%) could achieve up to approximately 94% control from current SO₂ emissions, or 98.4% from uncontrolled SO₂ emissions.

Hydrated Ash Reinjection: EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion SO₂ emissions by about 80%.¹⁸ This results in about 95% reduction from uncontrolled SO₂ emissions.

Hydrated Ash Reinjection + Limestone Injection Improvements: It may be possible to combine HAR (80% reduction) with improvements to the limestone injection system (85% reduction). This results in a potential 87.9% decrease from current SO₂ emissions or 96.9% reduction from uncontrolled SO₂ emissions.

Post-Combustion Controls – Wet Scrubbing: EPA noted a potential SO₂ removal efficiency of 94% for the post-combustion gas in the Bonanza BACT analysis¹⁹. Combined with the current limestone injection system, the overall potential control efficiency is 98.4% from uncontrolled SO₂ emissions.

¹⁷ Ibid., Page 100.

¹⁸ Barr, Appendix E, Page 93.

¹⁹ Ibid., Page 94.

Table 7 summarizes each available technology option and technical feasibility for SO₂ control for Nucla Unit 4.

Table 7: Nucla Unit 4 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 99% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further SO ₂ control
Fuel washing	Minimal	N
Limestone Injection Process Upgrades	~85% overall control efficiency ~40% increase from current control efficiency	Y
Dry Scrubbing (SDA)	~97% overall control efficiency ~87% increase from current control efficiency	Y
Limestone Injection Improvements + SDA	~98% overall control efficiency ~94% increase from current control efficiency	Y
Circulating Dry Scrubber	Unknown	N
Hydrated Ash Reinjection (HAR)	~95% overall control efficiency ~80% increase from current control efficiency	Y
HAR + Limestone Injection Improvements	~97% overall control efficiency ~88% increase from current control efficiency	Y
Dry Sorbent Injection (DSI)	<50% overall control efficiency	Y – will not provide further SO ₂ control
Wet Scrubbing	~98% overall control efficiency ~94% increase from current control efficiency	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Costs for SO₂ control options were evaluated based on analyses for similar systems proposed at other western CFB boiler units (Spiritwood and Bonanza). Refer to “Nucla APCD Cost Analysis” for more details. Depending on the control option, the Division also relied on additional submittals regarding Nucla feasibility and costs submitted on

Limestone Injection Process Upgrades: The Division relied on the U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) study to determine control efficiency for limestone injection upgrades. The Spiritwood BACT analysis used the cost of limestone in 2006 to determine limestone injection costs. The Division adjusted this cost using the Consumer Price Index (CPI), increasing limestone cost from \$80 per ton to \$87 per ton. The Division also calculated the additional amount of limestone (in tons per year) that will be needed to achieve an 85% control efficiency (or 40% increase from current control efficiency). These calculations result in an annualized cost of \$914,920 per year. Refer to “Nucla APCD Cost Analysis” for more details.

Dry Scrubbing (Spray Dry Absorber)/ Limestone Injection Process Upgrades + SDA: The Division again relied on the Spiritwood BACT Analysis to determine the cost of a spray dry absorber (SDA) system. The annualized cost (2006) for the Spiritwood CFB was \$2,644,412. The Division used the CPI to adjust this cost to \$2,814,108 and then scaled this cost up by the ratio of potential tons SO₂ removed at the Nucla CFB compared to tons removed at the Spiritwood CFB, and then added in a retrofit factor of 50% to consider the difficulty of the retrofit at Nucla as compared to a new CFB (Spiritwood). This results in an annualized cost of \$4,304,807. For limestone injection improvements combined with a SDA system, the Division combined annualized costs from both controls to result in an annualized cost of \$5,219,097. Refer to “Nucla APCD Cost Analysis” for more details.

Wet Scrubbing: Although Wet FGD systems provide higher levels of SO₂ removal over dry scrubbers, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using a wet scrubber versus the spray dry absorber is identified as \$12,902/ton in the Spiritwood BACT analysis²⁰, and \$10,540 per ton in the Bonanza BACT analysis.²¹ A wet scrubber at the Nucla Station should be expected to have even higher costs than these examples due to the retrofit factor. Therefore, a Wet FGD option will not be considered further in this analysis.

HAR/HAR+Limestone Injection Improvements: Study-level information for potential HAR systems at Nucla or any other EGU in the western part of the country were not available for use in evaluating costs. Therefore, the Division does not consider this option to commercially available at this time, and HAR will not be considered further in this analysis. However, HAR is technically feasible and will be considered in future analyses if more information becomes available.

Table 8 illustrates resultant SO₂ emissions for each technically feasible control option. Table 9 shows the SO₂ control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 3. The Division analyzed both annual and 30-day rolling average limits. The Department’s experience with power plants suggests that the maximum 30-day rolling average SO₂ emission rate is approximately 5% higher than the annual average emission rate.

²⁰ Barr, Appendix E, Page 95.

²¹ EPA, Deseret Power Electric Cooperative...Page 95.

Table 8: Nucla Unit 4 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 4		
		(tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,335	0.299	0.314
Limestone Injection Improvements (LII)	39.4	809	0.182	0.191
Hydrated Ash ReInjection (HAR)	80.0	267	0.060	0.063
Spray Dry Absorber (SDA)	87.0	174	0.039	0.041
HAR + LII	87.9	162	0.036	0.038
LII+SDA	93.9	81	0.018	0.019
Wet Scrubbing	94.0	80	0.018	0.019

Table 9: Nucla Unit 4 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LII	526	\$2,188,595	\$4,161	\$4,161
HAR	1,068	Not determined		
HAR+LII	1,173	Not determined		
SDA	1,162	\$7,604,627	\$6,547	\$8,520
LII+SDA	1,254	\$9,793,222	\$7,808	\$23,619
Wet Scrubbing	1,255	Not determined		

Factor 2: Time Necessary for Compliance

It is assumed that the Limestone Injection Improvements will not require any construction or capital improvements since the Unit has already been demonstrated at the higher Ca/S ratios during the CCTDP test project.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 – 5 years to implement the SDA or LII+SDA control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

There are no identified energy or non-air quality impacts associated with improvements to the Limestone Injection System. Thus, this factor does not influence the selection of this control.

Wet Scrubbing: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or “first in time - first in right,” and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado’s domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO₂ control technology consideration on commercially available once-through dry FGD controls, specifically, “lime spray dryers” (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO₂ control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO₂ emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO₂ emission reduction benefits (tons of SO₂ reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when compared to a SDA system when applied to the Nucla Unit 4 CFB boiler.

Spray dry absorber (SDA): Other Colorado facility have noted that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.²²

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: Other Colorado facility have documented additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,²³ which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

²² 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

²³ Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cetc/resources/pdfs/lifac/LIFAC_PPA.pdf

Factor 5 (optional): Evaluate Visibility Results

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Step 6: Select RP Determination

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO₂ emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO₂ capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO₂ emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO₂ system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein, the state has determined that the existing permitted SO₂ emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM₁₀)

Nucla Unit 4 is currently equipped with a four baghouse system to control PM/PM₁₀ emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

The baghouses performed over the 2006 – 2008 baseline period with PM and PM₁₀ emissions of 0.013 lb/MMBtu and 0.009 lb/MMBtu, respectively. During the CCTDP test project, the unit demonstrated particulate emissions ranging between 0.0072 to 0.0125 lb/MMBtu, corresponding to a removal efficiency of 99.9%²⁴. This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel.

²⁴ U.S. Department of Energy, Page 5.

A Division review of the PM/PM₁₀ emission limits in the current Title V permit revealed that these limits are for filterable PM/PM₁₀ emissions only.

Table 10 shows the most recent *verified* stack test data (2002). Another stack test was conducted in August 2010, but is not yet available for release due to ongoing analysis by the Division and Tri-State. Real-time data demonstrates that these baghouses are meeting >95% control. The Operating Permit (96OPMO168) limit is 0.03 lb/MMBtu for PM/PM₁₀ emissions (Conditions 1.1.1, 1.1.2). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 10: Nucla Unit 4 Stack Test Results (August 2002)

Pollutant	Unit 4 (lb/MMBtu)
Filterable PM ₁₀	0.014
PM ₁₀ Control efficiency	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM₁₀ determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is in the range of recent BACT determinations. Please refer to "Division RBLC Analysis" for more details about recent BACT determinations.

The State has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Therefore, a full 4-factor analysis is not needed to evaluate PM/PM₁₀ for the Unit 4 boiler.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Fuel Switching – Natural Gas or Alternate Coal Source
Selective Non-Catalytic Reduction (SNCR) system upgrades
Selective Catalytic Reduction (SCR) with flue gas reheat

Step 2: Eliminate Technically Infeasible Options

Tri-State provided an analysis of the requirements and costs associated with increasing the size of the existing SNCR system to allow for more frequent operation, and the Division has relied on this information (with some exceptions) in order to evaluate a full-time SNCR option. Due to lack of any specific feasibility or cost information related to SCR controls at Nucla Station, the Division relied on recent control evaluations performed for other CFB boilers in the western part of the country (the Spiritwood and Bonanza evaluations, noted in Section III.a. above).

Every BACT determination listed in the RACT/BACT/LAER Clearinghouse for CFB Boilers specifies SNCR; no SCR determinations or installations have been identified. This is likely due to the significantly high incremental costs of SCR systems, as discussed below.

As described above for SO₂ controls, fuel switching to natural gas or an alternative coal source is not considered technically feasible.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SNCR is considered a technically feasible alternative is Nucla Unit 4.

SCR: SCR systems are the most widely used post-combustion NO_x control technology for PC-fired boilers. SCR control involves injecting ammonia into the flue gas stream in the presence of a catalyst, and requires a temperature range of 500°F – 800°F. SCR systems are not considered feasible for CFB boilers because the particles present in the boiler exhaust act as catalyst poisons. However, the recent BACT analyses for the Spiritwood and Bonanza Units have considered the application of SCR technology following the particulate control device on CFB boilers in order to achieve 90% NO_x reduction. Since baghouse exhaust temperatures are too low to satisfy SCR requirements, reheating of the flue gas is required. NO_x control efficiencies of 90% are expected. The Division considers SCR a technically feasible alternative for Nucla Unit 4. Please see the cost section for more details regarding SCR.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

SNCR: The current SNCR system associated with Unit 4 is a small system using anhydrous ammonia injection for NO_x trim during period when emissions approach 0.4 lb/MMBtu (the permit limit is 0.5 lb/MMBtu). NO_x trim is required to ensure that the facility is able to meet the 1,987.9 ton per year permit limit on a rolling 12-month total. Tri-State notes that the unit is not in service the majority of the time. The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour, allowing only 8 days of continuous service. Tri-State also notes that there is such a wide variability in the effectiveness of SNCR for controlling NO_x emissions that only 10% control should be assumed, but provided no data to support this value. Note that 10% control over a baseline of 0.39 lb/MMBtu is 0.35 lb/MMBtu.

On August 17, 2006, Tri-State performed a stack test in order to ensure that ammonia slip emissions resulting from the newly installed SNCR system would not result in a significant emission increase (for PM₁₀) and trigger PSD review for the project. The test was completed at maximum and minimum boiler loads, and maximum ammonia injection rate (15.4 – 15.5 gallons per hour)²⁵. The test runs occurred during the following timeframes:

Low Load (80.4 MW)

Run 1: 7:28 – 8:28

Run 2: 9:14 – 10:14

Run 3: 10:44 – 11:44

High Load (109.2 MW)

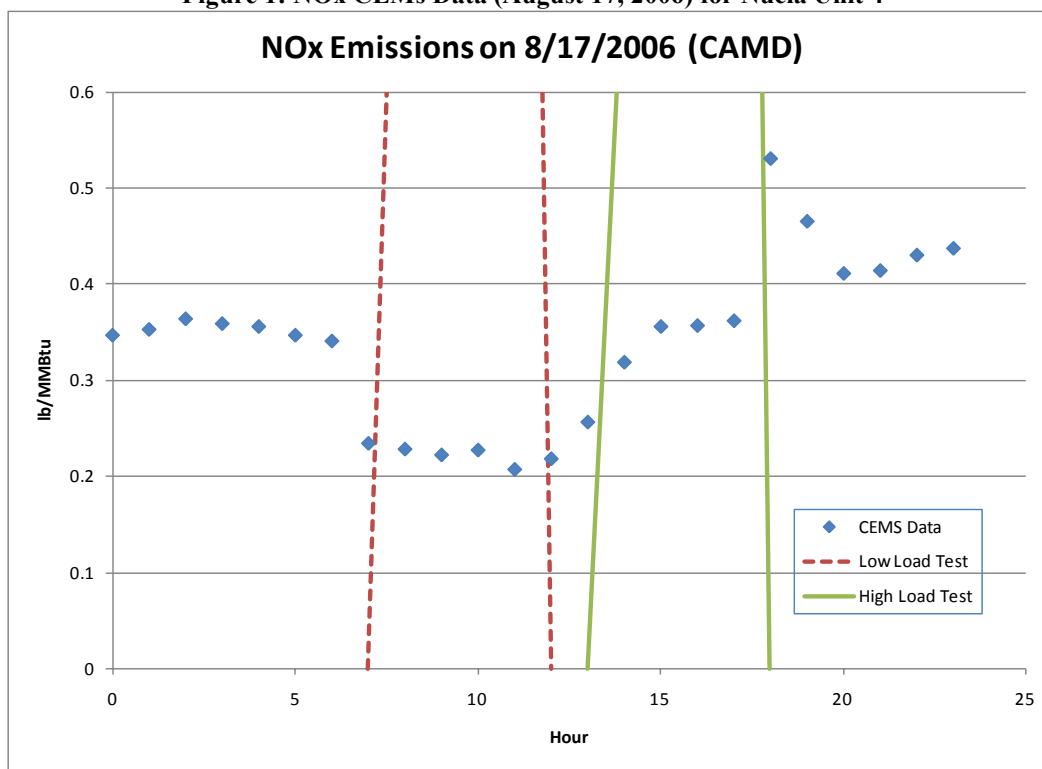
Run 1: 13:51 – 14:51

Run 2: 15:25 – 16:25

Run 3: 16:52 – 17:52

The NO_x CEMS data from CAMD for August 17, 2006 in Figure 1 shows an hourly NO_x rate during the low load test of 0.22 lb/MMBtu (corresponding to 43.6% control over the baseline), and an hourly NO_x rate during the high load test of 0.35 lb/MMBtu (corresponding to 10.3% control).

Figure 1: NO_x CEMs Data (August 17, 2006) for Nucla Unit 4



The low load rate of control is more in line with estimates for the SNCR systems in the Spiritwood and Bonanza BACT analyses (58%²⁶ and 47%²⁷, respectively).

²⁵ Colorado Department of Public Health & Environment, November 2, 2006. "Stack Testing Report, Nucla Station"

²⁶ Barr, Appendix E, Page 56.

²⁷ EPA, Deseret Power Electric Cooperative...Page 49.

The Division conducted an analysis to determine the typical load for Nucla Unit 4 using baseline data (2006 – 2008). From 2006 – 2008, Nucla ran at 97.6% load. This high load data indicates that 10.3% control is more reasonable. However, the Division and Tri-State both note that the existing small scale SNCR system is not designed for full-scale operation and would last about 8 days in continuous service and has never operated for an extended period of time. Tri-State further notes that given the design purpose of the existing system for injection to trim emissions as needed, the system is not engineered to achieve a specific percent reduction. The Division concludes that there is a significant amount of uncertainty surrounding the application of SNCR on CFB boilers due to lack of information at this time.

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Nucla Unit 4 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 20 – 70% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further NO _x control
Low NO _x Burners (LNB)	~10%	N – CFB boiler
Overfire air (OFA)	10 – 25% (alone)	N – CFB boiler
Selective non-catalytic reduction (SNCR)	20 – 40%	Y – small scale system already installed
Selective catalytic reduction (SCR)	70 – 90%	Y

Step 4: Evaluate Factors and Present Determination

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,²⁸ 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nucla Unit 4 to determine control efficiencies and annual reductions.

²⁸ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

Factor 1: Cost of Compliance

SCR: Although SCR systems provide significantly higher levels of NO_x removal over SNCR systems, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using SCR versus SNCR on a CFB Boiler is identified as \$25,315/ton in the Spiritwood BACT analysis²⁹, and \$40,297 per ton in the Bonanza BACT analysis³⁰. A SCR system at the Nucla Station should be expected to have even higher costs than these examples due to a retrofit factor and small size. Therefore, the Division considers that costs for SCR will be excessive. Additionally, site-specific costs for SCR on Nucla are not available at this time.

SNCR: The cost associated with installation of an upgraded SNCR system is shown below. Costs are based on values submitted by Tri-State on May 14, 2010.³¹ Refer to “Nucla APCD Cost Analysis” for more details. The Division used two discrete control efficiencies to demonstrate the significant uncertainty of the application of SNCR and the variation in resultant cost effectiveness.

Table 12 and Table 13 depict controlled NO_x emissions and control cost comparisons.

Table 12: Nucla Unit 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,675	0.387	
SNCR	10.3	1,503	0.347	0.399
SNCR	43.6	945	0.218	0.251

Table 13: Nucla Unit 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
SNCR	173	\$2,238,592	\$12,974	\$12,974
SNCR	730	\$2,238,592	\$3,065	---

²⁹ Barr, Appendix E, Page 57.

³⁰ EPA, Deseret Power Electric Cooperative...Page 51.

³¹ Tri-State, Page 3.

Factor 2: Time Necessary for Compliance

Tri-State states that the SNCR project could be implemented in a two to three year time frame, but also notes that³²:

“Projects of this size entailing a significant outage lasting eight weeks or more must be integrated into the long term schedule in order to coordinate with the management of the grid and for power replacement commitments. The date on which EPA SIP approval occurs is necessarily the starting point for any schedule including significant investments for engineering and design, procurement of equipment and contract commitments. In addition, the schedule would have to be integrated into the electric supply planning process.”

Tri-State has also described significant constructability challenges and balance-of-plant changes that will likely affect the timeframe for reconstruction of the SNCR project³³. Nucla station is located approximately 70 miles from the nearest interstate highway. The facility does not have rail service and is located 40 miles from the nearest commercial air terminal. Below freezing temperatures are expected seven months of the year, which affects soil excavation, structure foundations and concrete placement.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. The cost associated with increased power needs was addressed in the cost effectiveness study provided by Tri-State and is reflected in the costs shown in the tables above.

Installing SNCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid.

³² Ibid., Page 24.

³³ Ibid., Page 10.

With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; Tri-State has indicated that the larger quantity of on-site anhydrous ammonia storage required by the scale-up of the SNCR system will require the review and approval of new Risk Management Plans and Process Safety Management Plans. The larger tank may also trigger other state and local ordinances and requirements.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. Nucla has a limited, small-scale SNCR system for emissions trimming purposes already installed.

Step 6: Select RP Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NO_x RP for Nucla Unit 4 is the following NO_x emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO₂ and NO_x Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO₂ control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO₂ reduction performance, and other relevant technologies such as lime spray dryers and flue gas desulfurization. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NO_x control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO₂ and NO_x control scenarios for Nucla.

Finally, Tri-State shall propose to the state any preferred SO₂ and NO_x emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO₂ control and existing SNCR for NO_x reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NO_x reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NO_x limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure.

**Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Platte River Power Authority – Rawhide Energy Station**

I. Source Description

Owner/Operator:	Platte River Power Authority
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	1010026
Boiler Type:	Pulverized Coal Dry-Bottom Tangentially-Fired

The Platte River Power Authority (PRPA) Rawhide Energy Station is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. The Rawhide Energy Station consists of one coal fired steam driven electric generating unit (Unit 101), with a rated electric generating capacity of 305 MW (gross), and was placed into service in 1984. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and a lime spray dry absorber controls sulfur dioxide (SO₂). The boiler is equipped with low nitrogen oxide (NO_x) concentric firing system (LNCFS) burners with separated overfire air (SOFA) configuration for minimization of NO_x emissions, installed in 2005.

The Rawhide Station also has five natural-gas fired combustion turbines, designed to operate in a simple cycle mode, four rated at a heat input of 831.1 MMBtu/hour (approximately 82 MW) and one rated at a heat input of 1,400 MMBtu/hour (about 150 MW). Each turbine is equipped with integral dry low NO_x combustion systems and inlet air fog cooling systems and startup and shutdown duration average NO_x and CO emission limits determined to be Best Available Control Technology (BACT)¹ since each turbine is subject to Prevention of Significant Deterioration (PSD) provisions. These turbines were placed into service starting in May 2002, with the last turbine (150 MW) started up in June 2008. The primary use of these units is to meet Platte River's energy reliability and peak load requirements. The turbines operate on limited, intermittent, and unpredictable schedules as peak loading units. Additionally, the facility includes a number of fugitive dust sources. PRPA has prepared a Reasonable Progress (RP) analysis as well as supplemental information which can be found in "PRPA RP Submittals".

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Rawhide facility, and information about similar facilities to determine RP for PM₁₀ and SO₂ (available in the TSD). EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of SO₂, NO_x, or PM₁₀ equal

¹ Colorado Air Pollution Control Division, 2004. Colorado Operating Permit 03OPLR261: Rawhide Energy Station. Section II: Condition 1.7, pages 10 – 13.

to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for SO₂, NO_x and PM₁₀ to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines “emissions unit” as “any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term “unit” for purposes of Title IV (acid deposition control) of the federal act, or of the term “source” for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. ².” These *de minimis* levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 15 tons per year

Emissions Unit P301 serves as a detailed example of evaluating one “unit” in Table 1. As the PM₁₀ emissions from emissions unit P301 are below the *de minimis* level of 15 tons per year, it is exempted from any further analysis under RP.

Table 1: Unit Detail Example for *de minimis* Threshold

Unit P301 Breakdown	2006 – 2008 Average PM ₁₀ Emissions (Baseline Actual Emissions)
Solid Wastes Silo Rotary Unloader Discharge	0.41
Solid Wastes Hauling to Landfill	1.64
Solid Wastes Haul Truck Unloading	0.02
Active/Exposed Landfill Area	0.21
Waste Landfilling/Reclamation	0.39
Bottom Ash Excavation and Loading	0.02
Solid Wastes Silo Filling	0.00
Solids Vacuum Conveying System and Silo Filling	0.17
Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading	0.02
Unit P301 Baseline PM ₁₀ Emissions	3.01 << 15 (PSD threshold)

Rawhide Unit 101 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. PRPA submitted a “Rawhide NO_x Reduction Study” on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010. Table 2 depicts technical information for Rawhide Unit 101.

² Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Table 2: Rawhide Unit 101 RP-eligible Emission Controls and Reduction (%)

	Rawhide Unit 101
Placed in Service	1984
Boiler Rating, MMBtu/Hr for coal	3,000
Electrical Power Rating, Gross Megawatts	305
Description	Combustion Engineering tangentially fired, dry bottom steam generator/boiler firing pulverized coal.
Air Pollution Control Equipment	Fabric Filter (baghouse) for PM/PM ₁₀ control Spray Dryer Removal System for SO ₂ control
Special Features	Low NO _x Concentric Firing System (LNCFS) with separated overfire air (SOFA) installed in 2005
Emissions Reduction (%) ¹	NO _x – 49.6% SO ₂ – 83.1% PM/PM ₁₀ – 99.2/96.7%

¹Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM₁₀. For SO₂ estimates, CAMD data (average of 2006 – 2008) was used to calculate reduction %. The NO_x reduction is based on actual data from pre-2005 actual emissions. See “Rawhide APCD Technical Analysis” for further details. Not based on actual testing.

For the boiler, the Voluntary Emissions Reduction Agreement (VERA) permit limit for NO_x is 0.180 lbs/MMBtu on an annual average effective July 15, 2006. The Acid Rain permit limit for NO_x is currently 0.40 lbs/MMBtu on an annual average and the PSD/NSPS limit is 0.50 lbs/MMBtu on a 30-day rolling average.

In October of 2005, PRPA installed a low NO_x Concentric Firing System (LNCFS) with separated overfire air (SOFA) on Unit 101 that resulted in an approximate 50% reduction of NO_x emissions (from pre-2005 actual emissions) in accordance with the Voluntary Emissions Reduction Agreement entered into with the State of Colorado in 2002³.

Rawhide Unit 101 was initially installed in 1984 with a baghouse for particulate emission (PM/PM₁₀) control, with control efficiency exceeding 99.9%. This system was BACT at the time of initial startup and is still considered BACT currently.

The “Spray Dryer Removal System” for Unit 101 was considered a new control technology at the time of installation in 1984 and started up at the same time as Rawhide Unit 101. This system originally reduced SO₂ emissions by approximately 80% and 0.13 lbs/MMBtu (30-day rolling average) (from AP-42 emission calculations) according to Federal PSD emission standards at that time (0.2 lbs/MMBtu annually). In 2003, PRPA entered into a Voluntary Emissions Reduction Agreement with the State of Colorado to reduce SO₂ emissions to 0.09 lbs/MMBtu (annual

³ Colorado Air Pollution Control Division, 1992. Exhibit A: Division Evaluation of Nitrogen Oxides Emission Limitation and Regulatory Assurance Periods.

average) by upgrading the lime spray dryer system⁴. This upgraded system resulted in an approximate 30% emission rate reduction of SO₂ emissions from pre-VERA emission rates.

II. Source Emissions

Table 3 summarizes the NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 4 summarizes each unit at the facility and applicable NO_x, SO₂, and PM₁₀ actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 3. Summary of 2006 - 2008 Averaged Emissions - PRPA Rawhide Facility

NO _x (tons/year)	SO ₂ (tons/year)	PM ₁₀ (tons/year)
1,885	914	125

Table 4. Summary of 2006 - 2008 Averaged Emissions by Unit - PRPA Rawhide Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 101 Boiler	SO ₂ (tons)	943	928	869	913
	SO ₂ (lb/ MMBtu)	0.078	0.081	0.078	0.081
	NO _x (tons)	1,990	1,863	1,745	1,866
	NO _x (lb/ MMBtu)	0.163	0.162	0.173	0.166
	PM ₁₀ (tons)	109	113	101	108
	PM ₁₀ (lb/ MMBtu)	0.018	0.017	0.018	0.018
<i>Turbine Unit A (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.10</i>	<i>0.12</i>	<i>0.12</i>	<i>0.11</i>
	<i>NO_x (tons)</i>	<i>1.17</i>	<i>5.45</i>	<i>0.75</i>	<i>2.46</i>
	<i>PM₁₀ (tons)</i>	<i>0.20</i>	<i>1.12</i>	<i>0.13</i>	<i>0.48</i>
<i>Turbine Unit B (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.09</i>	<i>0.06</i>	<i>0.11</i>	<i>0.09</i>
	<i>NO_x (tons)</i>	<i>3.87</i>	<i>3.17</i>	<i>5.07</i>	<i>4.04</i>
	<i>PM₁₀ (tons)</i>	<i>0.77</i>	<i>0.58</i>	<i>0.99</i>	<i>0.78</i>
<i>Turbine Unit C (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.04</i>	<i>0.09</i>	<i>0.03</i>	<i>0.05</i>
	<i>NO_x (tons)</i>	<i>2.03</i>	<i>4.45</i>	<i>1.65</i>	<i>2.71</i>
	<i>PM₁₀ (tons)</i>	<i>0.33</i>	<i>0.80</i>	<i>0.30</i>	<i>0.48</i>
<i>Turbine Unit D (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.05</i>	<i>0.10</i>	<i>0.03</i>	<i>0.06</i>
	<i>NO_x (tons)</i>	<i>2.53</i>	<i>4.95</i>	<i>1.50</i>	<i>2.99</i>
	<i>PM₁₀ (tons)</i>	<i>0.45</i>	<i>0.85</i>	<i>0.26</i>	<i>0.52</i>
<i>Turbine Unit F (150 MW)**</i>	<i>SO₂ (tons)</i>			<i>0.38</i>	<i>0.38</i>
	<i>NO_x (tons)</i>			<i>20.45</i>	<i>20.45</i>
	<i>PM₁₀ (tons)</i>			<i>3.75</i>	<i>3.75</i>
<i>P201 Train Unloading Facility</i>	<i>PM₁₀ (tons)</i>	<i>0.60</i>	<i>0.01</i>	<i>0.01</i>	<i>0.20</i>
<i>P201 Active Coal Pile Reclaim</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.02</i>	<i>0.00</i>	<i>0.02</i>
<i>P201 Coal Silo Filling and Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Silo Discharge to Conveyor Belt</i>	<i>PM₁₀ (tons)</i>	<i>0.28</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Crushing and</i>	<i>PM₁₀ (tons)</i>	<i>0.33</i>	<i>0.02</i>	<i>0.02</i>	<i>0.12</i>

⁴ Colorado Air Pollution Control Division, 1992. Exhibit B: Division Evaluation of Sulfur Dioxides Emission Limitation and Regulatory Assurance Periods.

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<i>Conveying</i>					
<i>P201 Coal Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 In-Plant Silo Filling Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Pile Stockout</i>	<i>PM₁₀ (tons)</i>	<i>1.18</i>	<i>0.01</i>	<i>0.02</i>	<i>0.40</i>
<i>P201 Active Coal Storage Area</i>	<i>PM₁₀ (tons)</i>	<i>0.93</i>	<i>1.91</i>	<i>1.96</i>	<i>1.60</i>
<i>P201 Active Coal Pile Storage Area</i>	<i>PM₁₀ (tons)</i>	<i>0.95</i>	<i>2.56</i>	<i>2.56</i>	<i>2.02</i>
<i>P201 Coal Crusher Stockout</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0.00</i>
<i>P201 Coal Conveying</i>	<i>PM₁₀ (tons)</i>	<i>1.81</i>	<i>1.23</i>	<i>1.09</i>	<i>1.38</i>
<i>P301 Solid Wastes Silo Rotary Unloader Discharge</i>	<i>PM₁₀ (tons)</i>	<i>0.70</i>	<i>0.28</i>	<i>0.25</i>	<i>0.41</i>
<i>P301 Solid Wastes Hauling to Landfill</i>	<i>PM₁₀ (tons)</i>	<i>1.82</i>	<i>1.67</i>	<i>1.44</i>	<i>1.64</i>
<i>P301 Solid Wastes Haul Truck Unloading</i>	<i>PM₁₀ (tons)</i>	<i>0.04</i>	<i>0.02</i>	<i>0.01</i>	<i>0.02</i>
<i>P301 Active/Exposed Landfill Area</i>	<i>PM₁₀ (tons)</i>	<i>0.19</i>	<i>0.24</i>	<i>0.19</i>	<i>0.21</i>
<i>P301 Waste Landfilling/Reclamation</i>	<i>PM₁₀ (tons)</i>	<i>0.13</i>	<i>0.57</i>	<i>0.46</i>	<i>0.39</i>
<i>P301 Bottom Ash Excavation and Loading</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>
<i>P301 Solid Wastes Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.20</i>	<i>0.17</i>	<i>0.13</i>
<i>P301 Solids Vacuum Conveying System and Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.17</i>	<i>0.18</i>	<i>0.16</i>	<i>0.17</i>
<i>P301 Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.01</i>	<i>0.02</i>
<i>P401 Scrubber Lime Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0.01</i>	<i>0.01</i>	<i>0.00</i>
<i>P401 Recycle Ash Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.11</i>	<i>0.89</i>	<i>0.81</i>	<i>0.60</i>
<i>P501 Unpaved Site Roadways and Parking Lots</i>	<i>PM₁₀ (tons)</i>	<i>3.14</i>	<i>3.92</i>	<i>4.23</i>	<i>3.76</i>
<i>P501 PRS Soda Ash Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0.00</i>

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages for the Unit 101 Boiler are estimated to be 5-15% higher than the annual average emission rate (i.e. the maximum 30-day NO_x rolling average is likely about 0.190 lbs/MMBtu).

**Note that Unit F did not start up until June of 2008; therefore it was not operated in 2006 or 2007 and for only half of 2008.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Each of the five turbines at Rawhide Station was installed with an advanced dry low-NO_x combustion system that controls NO_x emissions to less than 9 ppm @ 15% O₂ as well as a gas turbine inlet air fog cooling system designed for optimal power augmentation during hot weather operations. . Each turbine is subject to BACT under the PSD provisions. The turbines are also

required to use pipeline quality natural gas as defined by the Acid Rain Provisions 40 CFR Part 72. The Title V permit enforces a compliance SO₂ emission factor of 0.0006 lb/MMBtu for each turbine. These combustion turbines are further evaluated within the source category “Combustion Turbines” in Section 8.2.3 of the Regional Haze SIP.

III. Units Evaluated for Control

As documented by PRPA, Rawhide Unit 101 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

Emission Unit	Specifications		
	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Rawhide Unit 101	8,853	0.24	5.42

Table 4 lists the units at Rawhide that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Rawhide Unit 101

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Rawhide Unit 101 ⁵	NO _x	7.2
	SO ₂	35 x %S = 8.5*
	PM/PM ₁₀	PM – 54.2**
		PM ₁₀ – 12.5

*%S = % of sulfur present in coal supply. For example, 35 x 0.24 = 8.5

**%A = % of ash present in coal supply. For example, 10 x 5.42 = 54.2

IV. Reasonable Progress Evaluation of Unit 101

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

PRPA identified one SO₂ control option:

Fuel Switching – Natural Gas or Colorado Coal

The Division requested that PRPA evaluate the option below, and received relevant information for this request on May 5, 2010:

Dry FGD upgrades

As discussed in EPA’s BART Guidelines⁶, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls.

⁵ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

⁶ EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Colorado Coal: The Division and PRPA both assert that the Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications and natural gas pipeline construction. Conversion from coal to natural gas would reduce SO₂ emissions by about 906 tons per year, or approximately 99% (using 2006 - 2008 CAMD data average)⁷. SO₂ emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the dry FGD – lime spray dryer system in place, Unit 101 currently achieves an emission rate of 0.07 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible as well as economically impractical to change coal supplies. The sulfur content of the Rawhide Unit 101 PRB coal supply is between 0.8 – 1.4 lb/MMBtu with most of the supply containing less than 1.2 lbs/MMBtu (based on northern Wyoming PRB coal mine reports). The average sulfur content in the coal is 0.29%. PRPA obtains coal for Rawhide Unit 101 from the Antelope Mine in Converse County, Wyoming, which has one of the lowest sulfur content of any mine in the county. PRPA additionally pays a premium to ensure higher Btu/lower sulfur coal. A review by the Colorado Geological Survey found that on average, Wyoming coal had similar sulfur content to Colorado coal⁸. Virtually all Colorado coal contains less than 1 percent sulfur and most of it contains less than half of that amount (0.5% or less)⁹. Therefore, the sulfur content of the Antelope Mine coal is similar, if not lower, than Colorado coal.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101. However, fuel switching to Colorado coal will not further reduce SO₂ emissions from Unit 101 and will not be considered further in this analysis.

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power

⁷ Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D of the SIP for detailed calculations.

⁸ Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998.
<http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf>

⁹ Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998.
<http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf>

plants¹⁰. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO₂ by using a slaked lime containing slurry that is sprayed into the flue gas and reacts with the SO₂ to form calcium sulfate, and then is subsequently dried by the heat of the flue gas, and collected in a particulate control device.

Rawhide Unit 101 was installed in 1984 with a “Spray Dryer Removal System” in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO₂ removal from the gaseous emission stream of a utility boiler. PRPA has since upgraded this system (in 2002) and currently achieves greater than 80% SO₂ removal, with an actual annual average of 0.07 lb/MMBtu and a permit limit of 0.09 lb/MMBtu on an annual average basis, 0.13 lb/MMBtu on a 30-day average, and 0.19 lbs/MMBtu on a 3-hour rolling average. This system exceeds EPA’s presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu¹¹. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA’s RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to Appendix D for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO₂ emissions found that lime spray drying processes have a range of design efficiencies from 70 – 96% and a median design efficiency of 90%; however, application conditions may differ (e.g. coal sulfur percent)¹².

PRPA submitted a SO₂ upgrade analysis to the Division on May 6, 2010 upon request regarding potential upgrades for the dry FGD scrubber system. PRPA asserts that operating the SO₂ scrubber at the 0.09 lbs/MMBtu VERA limit pushes many of the scrubber’s material handling and slurry preparation sub-systems to the limits of their design capacity. As part of the VERA scrubber improvements, the recycle ash pressure feeders were upgraded and the recycle ash conveying line was replaced with larger diameter piping to increase the recycle ash conveying capacity between the solids waste silo and recycle ash storage bin/silo. Moving beyond current levels of scrubber operation would require additional equipment upgrades and would reduce the existing redundancy in some critical scrubber sub-systems. Specifically, the recycle ash blowers, bin vent filter on recycle ash silo, feed slurry preparation pumps, and feed slurry tanks are all operating at maximum throughput levels or at the margin and would need to be replaced with larger capacity equipment. While there is usually available redundancy within the lime slaking sub-system, a lower SO₂ limit would diminish this available capacity and likely also require an upgrade to ensure adequate margin.

PRPA notes that the SO₂ scrubber has three atomizer reaction compartments that provide critical operating flexibility. The scrubber generally operates with all three compartments in-service,

¹⁰ Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

¹¹ Colorado Operating Permit 96OPLR142 pg. 5 – SO₂ 30-day rolling average limit is 0.13 lb/MMBtu.

¹² EPA, 2000. “Controlling SO₂ Emissions: A Review of Technologies.” Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.

which provides maximum reaction/residence time, eases SO₂ removal equipment demands, and minimize pressure drop. Though not a desirable operating mode, the scrubber is currently capable of operating at full load with only two atomizer compartments in-service. In addition to the improved scrubber performance, the current atomizer compartment redundancy provides critical atomizer operational and maintenance flexibility, ensuring environmental compliance, and providing for high SO₂ scrubber and unit availability. Achieving a lower SO₂ limit may compromise atomizer compartment redundancy, which will significantly diminish scrubber operational and maintenance flexibility. This loss of redundancy and flexibility will likely result in increase malfunctions and could also affect unit availability if load reduction is triggered.

Even with the potential scrubber equipment upgrades, additional SO₂ reductions will still present unacceptable operational challenges. SO₂ scrubbing is limited by scrubber outlet temperatures which must remain above the fluegas dew point with an adequate margin to prevent condensation and catastrophic damage to the baghouse. Over-spraying below minimum SDA outlet temperatures also results in higher moisture ash in the baghouse that is difficult to convey from the collection hoppers.

Given existing spray-down temperature constraints, reducing SO₂ emissions below 0.09 lbs/MMBtu requires additional lime to increase feed slurry reactivity. At higher SO₂ removal rates, the lime/SO₂ stoichiometry increases and more unreacted lime is carried-over with the flyash and scrubber waste to the baghouse. The higher lime content in the flyash and scrubber waste affects the fluidity of the material making it harder to pneumatically convey out of and between the baghouse hoppers, solid waste silo, and recycle ash storage bin/silo. Hopper bridging and conveying piping pluggage are significant operational and maintenance issues impacting SO₂ scrubber reliability. Lowering the SO₂ emissions below the VERA limit will increase the potential for scrubber and baghouse malfunctions.

PRPA examined BART-guideline dry scrubbing potential upgrades, with the following results:

-Use of performance additives: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO₂ scrubber performance additives applicable to the Unit 101 SDA system. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-Use of more reactive sorbent: Lime quality is critical to achieving the VERA emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with the VERA limit. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-Increase the pulverization level of sorbent: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO₂ scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements are designed to improve the reactivity of the slaked lime-milk slurry. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-Engineering redesign of atomizer or slurry injection system: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-nozzle design. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

The Division concludes that upgrades are not technically feasible for the Unit 101 Boiler.

Fuel switching to Colorado coal will not provide further SO₂ emission reductions. Rawhide Unit 101 has a SDA system for which the State has determined that no upgrades are feasible. Therefore, the Division has conducted a four-factor analysis for reasonable progress for fuel switching to natural gas regarding SO₂ reductions.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO₂ emissions by almost 100% from the boiler using EPA’s AP-42 emission factors¹³ and concurs with PRPA’s submittal.

Table 7 summarizes each available technology options and technical feasibility for SO₂ control on Rawhide Unit 101.

Table 7: Rawhide Unit 101 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90% ¹⁴	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO ₂ control
Fuel switching – different coal type	None	Y – will not provide further SO ₂ control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

¹³ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

¹⁴ Srivastava, R.K. Controlling SO₂ Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Factor 1: Cost of Compliance

In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about \$50 million by PRPA¹⁵. This results in an initial control cost, using EPA's Cost Control Manual¹⁶ to estimate annual operating costs, of about \$262,000 per ton of SO₂ removed annually¹⁷. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability, which was not taken into account in the 2008 study¹⁸.

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is \$25.5 million compared to natural gas at about \$240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration¹⁹. Therefore, this results in a significant annualized cost increase of \$233 million. Refer to Appendix D for details.

Table 8 and Table 9 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors.²⁰

Table 8: Unit 101 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)*	Resultant Emissions**	
		(tons/year)	(lb/MMBtu)
Baseline	---	913	0.08
Fuel Switching - NG	99%	7.7	0.0006

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.

** Division calculated from average baseline years (2006 – 2008). This is an annual average.

Table 9: Unit 101 SO₂ Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)*	Cost Effectiveness (\$/ton)*	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	n/a

¹⁵ PRPA, February 18, 2010. "Re: Rawhide Unit 101 NO_x Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

¹⁶ EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

¹⁷ Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.

¹⁸ PRPA, February 18, 2010. "Re: Rawhide Unit 101 NO_x Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

¹⁹ U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

²⁰ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

Fuel Switching - NG	906	\$237,424,331	\$262,169	\$262,169

* Division estimate based on PRPA submittal estimating direct capital cost at \$50,000,000, current delivered coal costs at ~\$20/ton, EPA Cost Control Manual, and EPA AP-42 emission factors for natural gas.

Platte River noted that the Division natural gas cost analysis does not account for replacement power for the lost generation. The Rawhide Natural Gas Conversion Study performed by B&V estimated that a 100% fuel switch would result in a loss of approximately 30 MW, in addition to the increased heat rate which was considered.

Platte River asserts that replacement power cost and associated emissions would depend on the specific source. Replacement with coal-fired sources would run in the \$20 - \$25/MWh range (\$5.3 - \$6.6 million/year), while natural gas-fired sources would run in the \$60 - \$125/MWh range (\$15.8 - \$32.8 million/year). Unaccounted NO_x emissions from the replacement power sources would likely be around 1.5 lbs/MWh (197 tons/year) for well combustion controlled coal-fired sources, and 0.36 lbs/MWh (47 tons/year) for natural gas-fired sources. The replacement power prices reflect current conditions and will need to be escalated over the 20-year 4-factor evaluation period. SO₂ emissions would likely be in the 0.7 lbs/MWh (92 tons/year) for well controlled coal-fired sources and 0.007 lbs/MWh (1 ton/year) for natural gas-fired sources. Table 7 below summarizes these costs and emissions.

Table 10: Unaccounted for Replacement Power Cost & Emissions Estimates (30 MW)

Power Source	Lower Cost (\$/MWh)	Lower Cost (\$ million/year)	Higher Cost (\$/MWh)	Higher Cost (\$ million/year)
Coal	\$20	\$5.26	\$25	\$6.57
Natural Gas	\$60	\$15.77	\$125	\$32.85
Power Source	NO _x (lbs/MWh)	NO _x (ton/year)	SO ₂ (lb/MWh)	SO ₂ (ton/year)
Coal	1.5	197	0.7	92
Natural Gas	0.36	47	0.007	1

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals²¹, the Division anticipates that, taking into account the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

²¹Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NO_x Reduction Feasibility Study." Pgs. 3-13 and 3-14.

Factor 3: Energy and Non-Air Quality Impacts

The Division has determined that there are not any negative energy or non-air quality related impacts related to fuel switching to natural gas for the Unit 101 boiler. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. **Error! Reference source not found.** depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Table 11: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO ₂ Control Scenario	Unit(s)	SO ₂ Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO ₂ rates	101	0.11	RMNP	20	---	---	6	---	---
dry FGD	101	0.09		n/a					
dry FGD	101	0.07		20	19	1	6	4	2
Fuel Switching - NG	101	0.001		n/a					

Table 12: Visibility Results - SO₂ Control Scenarios

SO ₂ Control Scenario	Unit(s)	SO ₂ Emission Rate	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
		(lb/MMBtu)	(deciviews)	(deciviews)	(%)
Max 24-hr SO ₂ rates	101	0.11	0.871		
dry FGD	101	0.09*	0.87	0.01	1%
dry FGD	101	0.07	0.84	0.03	3%
Fuel Switching - NG	101	0.001	0.00	0.87	100%

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “PRPA Modeling Summary” for more details.

Determination

The Division evaluated emission limit tightening based on current operations through the four-factor analysis. PRPA’s average 30-day rolling emission rate during the baseline period (2006 – 2008) was 0.09 lb/MMBtu. The maximum 30-day rolling emission rate during this period was 0.13 lb/MMBtu. Please refer to “Rawhide Cost Analysis” for more detail. The Division and PRPA agree that Rawhide can meet an emission limit of 0.11 lb/MMBtu (30-day rolling average).

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ RP is the following SO₂ emission rate:

Rawhide Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state has determined that these emissions rates are achievable without additional capital investment. Upgrades to the existing SO₂ control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO₂ limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

b. Filterable Particulate Matter (PM₁₀)

PRPA Unit 101 is currently equipped with two twelve-compartment fabric filter baghouses to control PM/PM₁₀ emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

PRPA states that the baghouses are able to control PM/PM₁₀ emissions to 0.03 lb/MMBtu and further notes that the baghouses meet a 99.9+% control efficiency. The source was tested on November 18, 2009 and ran at 0.0023 lb/MMBtu, 92% lower than the permit limit (Method 5 – filterable portion). This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel. A Division review of the PM/PM₁₀ emission limits in the current Title V permit revealed that these limits are for filterable PM/PM₁₀ emissions only.

A Division review of EPA’s RBLC revealed recent BACT PM/PM₁₀ determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is well within the range of recent BACT determinations.

The State has determined that the existing Unit 101 regulatory emissions limits of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent control option. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM₁₀. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM₁₀ is not needed for Rawhide Unit 101.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

PRPA identified eight NO_x control options:

Fuel Switching – Natural Gas

Selective non-catalytic reduction (SCNR)

Selective catalytic reduction (SCR)

Separated overfire Air (SOFA)

Low NO_x Burners (LNB)

LNB + SOFA

ECC – Enhanced Combustion Control

The Division also identified and examined the following additional control options:

Electro-Catalytic Oxidation (ECO)[®]

Rich Reagent Injection (RRI)

Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA[®] technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load²². While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the greater than 70% NO_x reduction already being achieved at Unit 101. Since ROFA[®] technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA[®] technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. NO_x emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the LNB+SOFA system in place, Unit 101 currently achieves an emission rate of 0.17 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible and economically impractical to change coal supplies. With fuel switching to natural gas, NO_x emissions were projected to drop from the current 0.17

²² Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

lbs/MMBtu to a rate of 0.1 lbs/MMBtu²³. However, this reduction would be diminished by the accompanying loss in boiler efficiency, increased boiler heat input requirement, and significant loss of generation resulting from natural gas firing.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101.

LNB/ROFA®/SOFA/LNB+SOFA: The boiler is already equipped with a tangentially-fired LNB+SOFA system that was installed in 2005. This system achieves an approximate 50% NO_x reduction (based on actual emissions).

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. The optimum temperature window for Rawhide Unit 101 will most likely occur somewhere at the top of the furnace and in the backpass of the boiler if SNCR is applied. SCNR is considered a technically feasible alternative for Unit 101.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 101 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Rawhide Station. Therefore, high-dust SCR is a technically feasible alternative for Rawhide Unit 101.

²³ PRPA, February 18, 2010. "Re: Rawhide Unit 101 NO_x Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

ECC: The enhanced combustion control system option for Rawhide Unit 101, submitted by PRPA, consists of a neural-net based combustion optimization subsystem (software and hardware) and companion real-time boiler combustion constituents and temperature measurement system. These system components are interfaced with the boiler's standard coordinated combustion control system (CCS). The ECC system continuously measures and monitors the dynamic boiler combustion constituents, temperatures and other process parameters. The ECC system then commands the CCS to manipulate variables such as combustion air damper positions, burner tilts, coal feeder speeds, and other process parameters to optimize fuel combustion and boiler efficiency, while controlling NO_x and CO emissions within targeted ranges. Optimizing the ECC requires periodic combustion testing and CCS tuning. ECC is a technically feasible option for Rawhide Unit 101.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler²⁴ and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers²⁵ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 101.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu²⁶. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year, or approximately 29% (using 2006 - 2008 CAMD data average)²⁷.

²⁴ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

²⁵ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

²⁶ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

²⁷ Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study²⁸ to conservatively approximate that Rawhide Unit 101 can achieve up to 30% control when SNCR is applied. PRPA asserts that NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. However, if ammonia slip is controlled closer to 2 ppm then achievable NO_x reduction efficiencies will be closer to 20 percent.

SCR: PRPA approximates that SCR can achieve an approximate 64% NO_x reduction from the current low 0.17 lb/MMBtu baseline emission rate. PRPA asserts that while a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for PRPA, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction from an assumed baseline emission rate of 0.5 lb/MMBtu.^{29,30} However, in the Division's experience and national CAMD emissions data (2009) reflect that an emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

Table 13 summarizes each available technology and technical feasibility for NO_x control.

Table 13: Rawhide Unit 101 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45-65%	Y – will not increase current NO _x reductions
SCNR	20 – 40%	Y
SCR – HTSCR	Up to 90%	Y-high-dust arrangement
SCR – LTSCR		
SCR – RSCR		
Fuel switching – Natural gas	20-70%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N
ECC	15-25%	Y

²⁸ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

²⁹ EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2.

<http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

³⁰ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.³¹ The PRPA-estimated SNCR costs for operating expenses is 44% for Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. The cost effectiveness for SNCR on Unit 1 is \$3,168 per ton NO_x reduced. Recent NESCAUM studies estimate SNCR retrofits achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing \$630 - \$1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.^{32,33} EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.³⁴

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NO_x emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NO_x Reduction Study, January 2009* noted that the SNCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SNCR project cost considerations were:

-
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101
- Three levels of automatic injection lances with retract system to accommodate SNCR reaction temperature and boiler turndown requirements.
- Computer flow/temperature modeling to establish optimum ammonia injection locations and flow patterns,
- Boiler waterwall modifications for injector lances and steam piping modifications for performance optimization,
- Electrical Motor Control Center switch gear upgrades and modifications to support urea system and ammonia delivery system,
- Reagent storage tank,
- Digital Control System (DCS) computer system hardware and control logic upgrades,
- Fluegas temperature and NO_x and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Interest costs during construction, and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns.

³¹ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

³² Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers."

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

³³ Amar, Praveen, 2000. "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

³⁴ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

Platte River notes that the SNCR cost effectiveness (\$/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons.

There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.³⁵ Although PRPA's estimates are greater than these ranges, the reasons above lead the Division to the conclusion that PRPA's cost estimates for SNCR are reasonable.

SCR: SCR reagent materials, such as urea and/or ammonia, primarily use a limited resource, natural gas. Therefore, future costs for these materials may fluctuate widely. These costs are not included in the overall \$/ton projections.

EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing PRPA's estimate, the Division found that the ratio of annual costs to the total capital costs for all control technologies projected by PRPA to be slightly lower than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for SCR for Unit 101 are 10.5% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments³⁶. Therefore, the Division concurs that PRPA's estimate is consistent with annual costs estimated by other facilities.

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NO_x emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NO_x Reduction Study, January 2009* noted that the SCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SCR project cost considerations were:

- Vertical oriented high-dust SCR reactor configuration,
- Construction crane access constraints due to north-side coal conveyor and ACI silo, and south-side underground 84 inch circulating water line,
- Preliminary design and layout analyses including foundations, structural columns, cantilevered support steel, and main trusses support structures,
- Modification to existing structures including demolition of ductwork between the economizer and the air heater inlet,
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101,

³⁵ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

³⁶ Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

- Induced draft (ID) fan higher hp motor replacement and retrofit issues,
- Auxiliary power and switch gear upgrades and modifications to support two new ID fan motors,
- Digital Control System (DCS) computer system hardware and control logic upgrades including new electrical and controls building located adjacent to SCR,
- NO_x and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Three layer (two catalyst and one initial spare) reactor sizing for maximizing catalyst utilization,
- Reactor design to accommodate both ceramic honeycomb and plate type catalyst products to insure future procurement flexibility,
- Rerouted underground utilities (bottom-ash sluice trench and drain piping) due to SCR foundation requirements,
- Added superstructure costs due to fully enclosed plant, including boiler and air heater areas for cold-weather concerns requiring roof and wall penetrations and modifications,
- Higher structural costs due to high wind loading ,
- High gas temperature design issues (>800°F economizer gas temperature results in higher grade catalyst and steel issues), and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns,
- Interest costs during construction, and
- Lost generation revenue costs during outage.

Platte River notes that the SCR cost effectiveness (\$/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons. The Division asserts that \$/KW is not an appropriate metric when a detailed cost estimate has been developed. \$/KW is rough estimate of controls for back of the envelope discussions and should not serve as cost estimate in light of more refined estimates. Therefore, the Division did not adjust PRPA's estimates for capital costs.

Fuel Switching – Natural Gas: In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about \$50 million. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year (using 2006 - 2008 CAMD data average). This results in an initial control cost, using EPA's Cost Control Manual to estimate annual operating costs, of about \$436,000 per ton of NO_x removed annually³⁷. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability. Tables 9 and 10 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors. The annual cost to control was determined using a capital

³⁷ Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D SIP for detailed calculations.

recovery factor based on an approximate 8% interest rate. Refer to “Rawhide Cost Analysis” for more details.

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is \$25.5 million compared to natural gas at about \$240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration³⁸. Therefore, this results in a significant annualized cost increase of \$233 million. Refer to Appendix D for details.

ECC: PRPA worked with three different vendors on an enhanced combustion control pilot system. The cost estimates provided are from this pilot project. The annualized cost of approximately \$288,500 is much lower than SNCR, which achieves about the same amount of control. This is little available cost information regarding this type of boiler modification. Since the costs are comparable or lower than other pre-combustion technologies, the Division concurs that PRPA’s cost estimate is reasonable.

Table 14 and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 14: Unit 101 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,866	0.166	
ECC	24.0	1,418	0.126	0.145
SNCR	27	1,362	0.121	0.140
Fuel Switching - NG	29.2**	1,321	0.118	0.135
SCR	63.5	681	0.061	0.070

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.

** Control efficiency provided in PRPA’s analysis based on 0.17 lb/MMBtu NO_x input, equivalent to 2006 – 2008 baseline conditions. Refer to “Rawhide Cost Analysis” for more information.

Table 15: Unit 101 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---

³⁸ U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

ECC	448	\$ 288,450	\$644	\$644
SNCR	504	\$1,596,000	\$3,168	\$23,357
Fuel Switching - NG	545	\$237,424,331	\$435,681	\$5,735,260
SCR	1,185	\$12,103,000	\$10,214	(\$352,073)

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals³⁹, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

PRPA anticipates that the time necessary for completing design, permitting, procurement, control equipment installation, and system startup and shakedown, after SIP approval, would be approximately 2-3 years for SNCR and 3-4 years for SCR. These timeframes may also vary somewhat to schedule the necessary major maintenance outage with other regionally affected utilities. The ECC option timeframe is much shorter due to the fact that PRPA has already been working with independent vendors on this system. Therefore, this system could be functional within 6 months of SIP approval.

Factor 3: Energy and Non-Air Quality Impacts

SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR and SNCR reagent injection system have minimal power requirements.

Post-combustion add-on control technologies like SCR and SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. 100 – 300 kW is less than 0.5% of the power generated by the Unit 101 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in

³⁹ Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. “Black Hills Clark Station NOx Reduction Feasibility Study.” Pgs. 3-13 and 3-14.

the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. PRPA has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to Appendix D for more information.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor doesn't influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NO_x emission rates to determine control efficiencies and annual reductions.

Table 16: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NO _x Control Scenario	Boiler	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr NO _x rate	101	0.302	Rocky Mountain National Park	20	---	---	6	---	---
ECC	101	0.126		20	6	14	6	1	5
SNCR	101	0.121*		n/a					
Fuel Switching - NG	101	0.118*		n/a					
SCR	101	0.061		20	1	19	6	0	6

Table 17: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Boiler	NOx Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr NOx rate	101	0.302	0.87	---	---	---
ECC	101	0.126	0.42	0.45	52%	\$642,428
SNCR	101	0.121*	0.41	0.46	53%	\$3,469,565
Fuel Switching - NG	101	0.118*	0.41	0.47	54%	\$509,494,272
SCR	101	0.061	0.28	0.59	68%	\$20,548,387

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “PRPA Modeling Summary” for more details.

Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE) SOURCE CATEGORY

NOx Emission 4-Factor Analysis for Reasonable Progress (RP)

I. Source Description

The review of potential RP sources involved an evaluation all Colorado stationary sources with actual SO₂, NO_x or PM₁₀ emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. There were one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants which were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I Area (CIA) boundary. The Q/d was calculated for each source, where “Q” is the sum of the SO₂, NO_x and PM₁₀ emissions in tons per year and “d” is the source distance from the nearest CIA in kilometers; which resulted in the identification of seventeen (17) point sources with a Q/d $\geq$ 20. The Q/d threshold was determined based on conducting a sensitivity analysis of previous subject-to-BART CALPUFF modeling of BART eligible sources that indicated a value of 20 represented about 0.3 deciview of change in visibility impairment.

An evaluation of the 17 RP sources identified only one source directly associated with RICE equipment, a compressor station (Ignacio B Plant) that uses natural gas-fired RICE. The Ignacio B compressor station is located southeast of Durango on Southern Ute Indian Tribal land which is outside the jurisdiction of the State of Colorado; consequently the Division is unable to provide a 4-factor NO_x control evaluation and associated determination for this particular RP source.

In addition to individual point sources with a Q/d $\geq$ 20, the Division evaluated categories of sources that were determined to be significant and subject to evaluation under RP. The Colorado point source emission inventory indicates that stationary internal combustion engines (see below table), particularly large industrial natural gas fired reciprocating internal combustion engines (RICE), are a significant source category of NO_x emissions that represents about 16% of statewide point source NO_x emission inventory¹.

Colorado Internal Combustion Engine NO_x Emissions from the PRP 2018b Emission Inventory

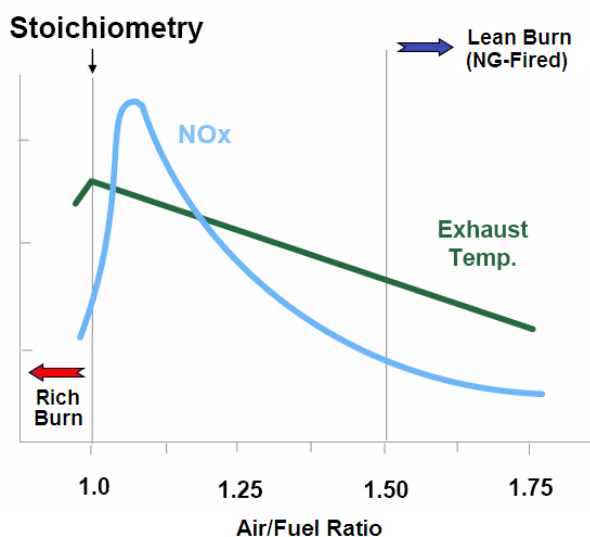
Category	Subcategory	2018 NO _x Emissions (tpy)
Industrial	Natural Gas Fired	16,199
	Large Bore Engine	256
	Distillate Oil (Diesel)	225
	Liquefied Petroleum Gas	27
	Gasoline	24
Electric Generation	All	4,323
Commercial/Institutional	All	1,152
Engine Testing	All	5
Total:		22,210

¹ Total 2018 Statewide Point Source NO_x is projected at 101,818 tons per year based on the WRAP PRP2018b emission inventory.

The majority of the RICE operating in Colorado are associated with the oil and gas industry. The power generated by these RICE is generally used to compress natural gas for line transmission or to generate electricity in remote locations. The designation “large” refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this document.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios (AFR). If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. An air-to-fuel ratio controller uses exhaust O_2 to control the combustion ratio. RICE that are operated with fuel-rich ratios (exhaust $O_2 < 0.05\%$) at or near stoichiometric, are called rich-burn engines (RB), or alternatively RICE that operate with air-rich ratios (exhaust $O_2 > 7$ to 8%) above stoichiometric, are called lean-burn engines (LB). The undesirable combustion emissions from natural gas fired RICE are primarily nitrogen oxides (NO_x , consisting of primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). Oxides of nitrogen are formed by thermal oxidation of nitrogen from the air. CO and VOCs are byproducts of incomplete combustion.

NO_x and Exhaust Temperature Change with Air/Fuel Ratio



There are site specific considerations for using either type of engine, depending on the parameters that are most important for the operator. RB engines have lower oxygen levels and higher temperatures in the engine exhaust, which allows for the use of a 3-way catalyst (non-selective catalyst) which is effective at reducing NO_x , CO, and VOCs in the exhaust. Because the air-to-fuel ratio is rich with fuel, more fuel is used, which results in increased combustion temperatures, increased engine power, and decreased engine efficiency. Higher temperatures result in more NO_x being formed during the combustion process. Conversely, LB engines have higher oxygen levels in the combustion chamber, which decreases the combustion temperature thereby reducing how much NO_x is formed. Because the air-to-fuel ratio is lean with fuel, less fuel is used, which results in decreased combustion temperatures, decreased engine power, and increased engine efficiency. The use of an oxidation catalyst on a lean burn engine similarly results in decreases in CO and VOC emissions but the performance for controlling NO_x

emissions is very low because LB engine exhaust temperatures are below the optimum temperature range for effective NO_x control due to reduced catalyst reactivity. The above chart provides the relative change in NO_x emissions and engine exhaust temperature as a function of air-to-fuel ratio.

II. Natural Gas-Fired RICE Source Category Emissions - Statewide

Since natural gas-fired RICE comprise over 73% of the NO_x emissions in statewide RICE source category, the analysis will focus exclusively on NG-fired RICE. In 2018, the statewide NG-fired RICE source category is projected to contribute the following emissions:

Statewide Natural Gas Fired RICE Source Category Emissions*

Total Number of Sources with NG-fired RICE	Pollutant	Number Sources with RICE > 100 tpy	Number Sources with RICE > 40 tpy	Number Sources with RICE < 2 tpy	2018 Emissions (tpy)
497	NO _x	40	85	82	16,199
	SO ₂	0	0	486	115

* Point Source Natural Gas Fired RICE Emissions based on APEN report data supplied to the WRAP for the PRP2018b Emission Inventory.

Based on the PRP 2018b emission inventory, statewide there are about 497 sources using NG-fired RICE and about 40 sources that emit NO_x emissions greater than 100 tons per year. During a recent 2008 rulemaking, the Division conducted a detailed analysis of RICE outside the 9-county metro area (referenced as “statewide”) and determined that there are about 1,340 NG-fired RICE statewide², which includes about 593 NG-fired RICE over 500 hp as indicated in the below table.

Statewide Natural Gas-Fired RICE Over 500 Horsepower Outside the 9-County Metro Area

SCC Description	Number of RICE
2-CYCLE LEAN BURN (NG)	84
4-CYCLE LEAN BURN (NG)	204
4-CYCLE RICH BURN (NG)	305
Total:	593

In addition to the 593 RICE listed above, the 2004 Denver Early Action Compact rulemaking identified 139 NG-fired RICE³ over 500 hp that were subject to control requirements of non-selective catalytic reduction on 79 RB RICE and oxidation catalyst on 60 LB RICE in the 9-county metro area. Consequently, there are a total of 732 NG-fired RICE over 500 hp in Colorado.

It is difficult to readily determine the exact number of NG-fired RICE below 500 hp but over 100 hp because engines were sometimes grouped together in a single permit. However, a preliminary review of APEN data indicates that there are approximately 234 NG-fired RICE below 500 hp but over 100 hp. The remaining 513 NG-fired RICE have design capacities under 100 hp.

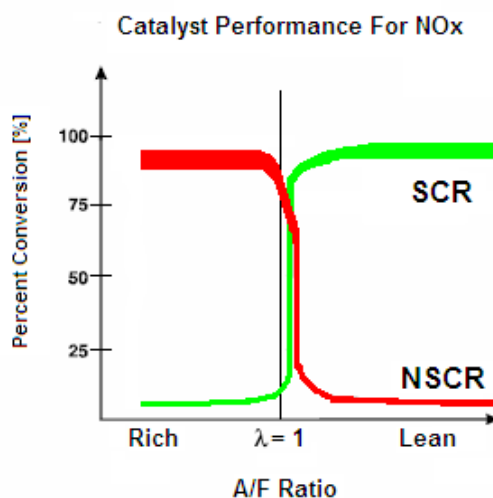
² The Statewide RICE count does not include RICE in the 9-county metro area which was subject to an earlier rulemaking, thus the actual number of total RICE in the State of Colorado is higher.

³ Reference Final Economic Impact Analysis – Revisions to Regulation No. 7, February 11, 2004.

III. NO_x Control Technology Evaluation

Step 1: Identify All Available Technologies

Generally in retrofit applications, NO_x emissions from engines can be reduced either through combustion controls or adding post combustion emission controls (e.g., catalysts) to the engine exhaust. Catalysts are designed to speed up desired reactions. The rate of chemical reaction is a function of several parameters, including air-to-fuel ratio, engine load and exhaust temperature. Catalysts have specific temperature ranges that must be achieved for optimum NO_x reduction. The below diagram roughly depicts the catalyst performance for conversion of NO_x emissions using a NSCR and SCR on rich and lean burn engines.



Six retrofit technologies have been identified to lower NO_x emissions from rich/lean burn natural gas-fired internal combustion engines.

1. Lean Burn – Air/Fuel Ratio Adjustment
2. Lean Burn – Ignition or Spark Timing Retard
3. Rich Burn – Non Selective Catalytic Reduction (NSCR) Catalyst (3-way)
4. Rich/Lean Burn – Selective Non-Catalytic Reduction (SNCR)
5. Lean Burn – Selective Catalytic Reduction (SCR)
6. Replacement with electric motors

Colorado requires that emissions from rich burn RICE (applicable statewide⁴) be controlled using a 3-way catalyst (NSCR) with air/fuel controller if control costs are below \$5,000 per ton. Few of the statewide rich burn RICE demonstrated control costs exceeding the \$5,000 cost off-ramp. Consequently, the state concludes that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide. Therefore, the following analysis does not evaluate lower benefit NO_x controls such as air/fuel adjustment or ignition/spark timing adjustment for rich burn RICE despite the technical feasibility of such controls.

⁴ Reference Colorado Regulation Number 7, see section XVII.E.3.a

It is important to clarify that lean burn RICE are not subject to NO_x retrofit controls because Regulation 7 requires statewide lean burn RICE over 500 HP to install retrofit oxidation catalyst control, which is only effective for control of VOC and CO, if the VOC control cost is under \$5,000 per ton. This Regulation was effective as of July 1, 2010.

Step 2: Eliminate Technically Infeasible Options

Technology #1 - LB (Air/Fuel Ratio Adjustment): This technology is technically feasible.

Technology #2 - LB (Ignition/Spark Timing Retard): This technology is technically feasible.

Technology #3 – RB (3-way NSCR Catalyst): This technology is technically feasible.

Technology #4 – RB/LB (SNCR): This technology is technically feasible.

Technology #5 – LB (SCR): This technology is technically feasible.

Technology #6 – Replace RICE with electric motors: This technology is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

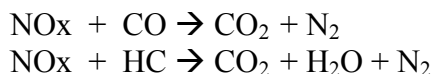
Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment): In lean burn engines, increasing the air to fuel ratio decreases the NO_x emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NO_x formation. In order to avoid de-rating, combustion air to the engine must be increased at constant fuel flow, requiring a turbocharger. An automatic air-to-fuel ratio controller also will be required. This control method is most effective on fuel-injected engines. Typically, for lean burn engines the air/fuel ratios are increased from normal levels of 50% excess air up to excess air levels of 240%. The upper limit is constrained by the onset of misfiring at the lean limit. This condition also increases CO and VOC emissions. Naturally aspirated engines and engines with fuel injected into the intake manifold plenum do not have identical air-to-fuel ratios in each cylinder, this results in limited ability to vary the A/F ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions. On lean burn RICE, air/fuel ratio adjustment generally achieves about 5-30% reduction⁵ in NO_x emissions but is very specific to each engine and typical loading.

Technology #2 - Lean Burn (Ignition/Spark Timing Retard): This adjustment lowers NO_x emissions by moving the ignition event to later in the power stroke. Because the combustion chamber volume is not at its minimum, the peak flame temperature will be reduced, thus reducing thermal NO_x formation. Ignition timing retard is applicable to all engines. It is implemented in spark ignition engines by changing the timing of the spark, and in compression ignition engines by changing the timing of the fuel injection. For variable loads, an electronic ignition/injection control system is required. On lean burn RICE, ignition/spark timing retard generally achieves about 20% reduction in NO_x emissions.

Technology #3 - Rich Burn NSCR: This technology uses three-way catalysts to promote the reduction of NO_x to nitrogen and water. CO and hydrocarbons are simultaneously oxidized to carbon dioxide and water. NSCR is applicable only to rich burn engines (i.e. those with exhaust oxygen concentration below about one percent). NSCR, in addition to the catalysts and catalyst

⁵ Reference – State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

housing, require an oxygen sensor and automatic air to fuel ratio controller to maintain an appropriate air to fuel ratio. Some ammonia can be produced particularly as the catalyst ages. The simplified reactions governing NSCR are as follows:



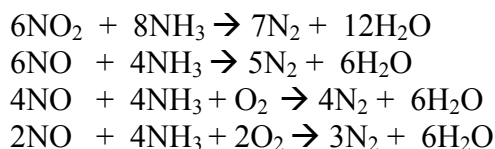
The exhaust passes over a catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N₂, CO₂ and H₂O. Typical exhaust temperatures for effective removal of NO_x are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness typically around 80 to 90 percent NO_x control. Extremely tight control of the air to fuel ratio operating range is accomplished with an electronic air to fuel ratio controller.

Technology #4 - Rich/Lean Burn SNCR: SNCR is applicable to both lean burn natural gas and diesel engines. SNCR involves injecting ammonia or urea into regions of the exhaust with temperatures greater than 1200 – 2000 degrees Fahrenheit. The nitrogen oxides in the exhaust are reduced to nitrogen and water vapor. Additional fuel is required to heat the engine exhaust to the correct operating temperature. Heat recovery from the engine exhaust can limit the additional fuel requirement and concurrent additional emissions from heating exhaust gases. Ten parts per million of ammonia (slip) is considered reasonable for SNCR. Temperature is the operational parameter affecting the reaction - as well as degree of contaminant mixing with reagent and residence time. Additional control of particulate matter (up to 85% diesel particulate matter), volatile organic compounds (up to 90 percent) and carbon monoxide (up to 70 percent) may be realized by the afterburning effect of this technology. On both rich burn and lean burn RICE, SNCR generally achieves about 50 to 95% reduction in NO_x emissions.

Technology #5 – Lean Burn SCR: SCR uses catalyzed reduction of NO_x with injected ammonia or urea solution. This technology is applicable to lean burn engines only (i.e., those with greater than about one percent exhaust oxygen, as oxygen is a reagent in the selective reduction reaction.) SCR may be used with lean burn (SI), dual fuel or diesel engines (CI). SCR produces unreacted ammonia (slip) and monitors are necessary to provide correct control of ammonia injection rates to minimize slip. When used with diesel engines, it is important to use a low sulfur fuel and sulfur resistant catalyst. Sulfur dioxide in the exhaust can be oxidized over the SCR catalyst to sulfuric acid mist, and when combined with unreacted ammonia, produces sulfate particulate.

For an SCR system using urea, the first stage of the catalyst bed is the hydrolysis catalyst, which converts the urea to ammonia. In the second stage of the catalyst, the ammonia and NO_x react to form nitrogen gas and water with some unreacted ammonia passing through. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450°F and 800 °F. For higher temperatures (675 °F to 1100 °F), zeolite catalysts may be used. Both the base metal and zeolite catalysts are sulfur tolerant for diesel engine exhaust. Precious metal SCR catalysts are useful for low temperatures (350 °F to 550 °F). When using precious metal SCR catalysts, attention should be paid to the fuel sulfur content and the appropriate formulation selected. This is not a concern with RICE fired with natural gas.

Reactions of NO_x over SCR catalyst:



An SCR system consists of reagent storage, feed and injection system, and a catalyst and catalyst housing. Predictive mapping of engine operating parameters can be used to monitor and control the SCR reaction. Precious metal catalysts can reduce NO_x by 80%. Zeolite catalysts can reduce NO_x by 90% with minimal sulfur dioxide to sulfur trioxide conversion. Exhaust gas temperatures greater than the upper limit (850 F) will pass the NO_x and ammonia unreacted through the catalyst.

Technology #6 – Replace RICE with electric motors: This control technology results in complete reduction of NO_x emissions at the RICE location, although the electric power provided to the motor must be supplied by a power plant located at some distant location. There is a net reduction in NO_x emissions from consolidating operations although the amount of reduction depends on the distance from the power plant as transmission line losses reduce the effectiveness of this control. Another consideration is the proximity to high voltage lines which may limit the practicality of this control option in rural areas.

The below table summarizes each available technology and the technical feasibility for NO_x Control.

NG-Fired RICE – NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
<i>Lean Burn (Air/Fuel Ratio Adjustment)</i>	~5-30%	Y
<i>Lean Burn (Ignition/Spark Timing Retard)</i>	~20%	Y
<i>Rich Burn NSCR</i>	~80-90%	Y
<i>Rich/Lean Burn SNCR</i>	~50-95%	Y
<i>Lean Burn SCR</i>	~80-90%	Y
<i>Replace RICE with electric motors</i>	~60-100%	Y

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment): In naturally aspirated LB engines and LB engines where fuel is injected into the intake manifold plenum, each cylinder does not have an identical air-to-fuel ratio, thus changes in the A/F ratio are very limited and therefore of little benefit, although the cost of such adjustment is minimal. Additional NO_x emission reduction benefit is gained through the addition of a turbocharger and an automatic air-to-fuel ratio controller. The cost of adding these controls is very specific to the engine size and design but generally ranges between \$320 to \$8,300 per ton⁶ of NO_x reduced.

⁶ Reference – Supplementary Information for Four Factor Analysis by WRAP States, EC/R Incorporated, May 4, 2009, see table 3-3.

Technology #2 - Lean Burn (Ignition/Spark Timing Retard): Based on a general analysis of NG fired RICE for the WRAP states⁴, the cost of this control ranges between \$310 to \$2,000 per ton of NO_x depending on engine size and firing design.

Technology #3 - Rich Burn NSCR: Regulation Number 7 requires rich burn RICE over 500 HP to install retrofit NSCR controls if the cost of control is under \$5,000 per combined ton (NO_x and VOC) statewide. This Regulation was effective as of July 1, 2010. None of the operators of rich burn RICE outside the metro-area ozone non-attainment area submitted information demonstrating control costs in excess of \$5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller.

Emission Reduction from NSCR Retrofit of RICE > 500 hp

Statewide RICE Category*	Count**	NO _x Reduction (tpy)
Lean Burn ≥ 500 HP	288	minimal***
Rich Burn ≥ 500 HP	305	5,800

Notes:

* This data represents statewide RICE, excluding the 9-county metro area (ozone non-attainment area) which was addressed in an earlier rulemaking for the Early Action Compact.

** Data obtained from 2008 APENs

*** Retrofit NSCR for lean burn RICE was not required because of minimal NO_x reduction

Annualized Costs for Rich Burn RICE Control Device

Item	Capital Costs (one time)	O&M (recurring)	Total Annualized Cost (15 yrs)
NSCR with AFR Controller*	\$35,000	-	
Operating	-	\$6,000	
Subtotal Costs:	\$35,000	\$6,000	
Annualized Costs:	\$4,851	\$6,000	
			\$10,851

Notes:

* Cost estimates obtained from "Denver Early Action Compact Analysis of Stationary Sources" Nov. 3, 2003

Costs Associated with Statewide Retrofit of Natural Gas-fired RB RICE ≥ 500 HP

Category	Number of Devices	Annualized Cost per Device	Total Device Cost	NO _x Reduction [tpy]	\$/ton
NSCR & AFR Controller	305	\$10,851	\$3,309,555	5,800	\$571

Technology #4 - Rich/Lean Burn SNCR: SNCR usually requires reheating of the exhaust to achieve the proper temperature range for effective NO_x conversion; this is particularly true for lean burn RICE where excess oxygen results in exhaust temperatures well below the required levels. The Division was unable to acquire cost information for this control option, thus no cost estimates have been provided. The scarcity of SNCR data on NG-fired RICE may suggest other post combustion NO_x controls are preferred, particularly SCR which has more reliable control effectiveness under a variety of load conditions.

Technology #5 – Lean Burn SCR: Depending on the engine size, catalyst used and the level of sophistication of the control system, SCR costs generally range about \$430 to \$4,900 per ton of NO_x reduced.

Technology #6 – Replace RICE with electric motors: Depending on the engine size, length and capacity of the power line required, the costs generally range from \$100 to \$4,700 per ton of NO_x reduced⁷. These costs do not include any potential impact from increases in electrical load at the power plant. The true cost of replacing RICE with electric motors is dependent on the distance from the power plant and the amount of compression power required. In actuality, larger compressor stations with multiple large engines would produce significant increased demands at a nearby power plant and possibly significant demands on the line transmission system that would escalate the costs to levels much higher than the \$4,700 control cost. Colorado has about 40 large compressor stations, thus the estimation of costs would require a case-by-case analysis which was not done for this RP evaluation. Although, if all statewide RICE (above 500 horsepower) were converted to electric motor compression, then a minimum of approximately 600 MW of extra generating capacity would be required. Realistically, the actual generating capacity required is probably much higher when transmission losses and peak demand cycles are factored into the load demands.

Factor 2: Time Necessary for Compliance

Technology #1, 2, 4, 5 and 6: If Colorado was to decide to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules and undergo Legislative review. Subject sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_x control⁸. However, the time necessary will depend on the type and size of the unit being controlled. For instance, in past rulemakings, typically 18 months may be required to install a particular control technology on hundreds of engines. Additional time, up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve the NO_x emission reductions for reciprocating engines is estimated at about 5 years.

Technology #3: This control option is implemented and was effective on July 1, 2010.

Factor 3: Energy Impacts and Non Air-Quality Impacts

In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value⁹ of about 2.5%. This increased fuel consumption would result in increased CO₂ emissions. Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed. This would produce an increase in CO₂ emissions. In addition, spent

⁷ Bar-Ilan, Amnon, Ron Friesen, Alison Pollack, and Abigail Hoats (2007), *WRAP Area Source Emissions Inventory Protection and Control Strategy Evaluation - Phase II*, Western Governors Association, Denver, Colorado, Chpt 4.

⁸ Institute of Clean Air Companies (2006), *Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources*.

⁹ Center for Alternative Fuels, Engines & Emissions (2005), *Alice Austen Ferry Emissions Tests*, M.J. Bradley & Associates, Manchester, NH, Page 13.

catalyst would have to be changed periodically, producing an increase in solid waste disposal¹⁰. Replacing RICE with electric motors may require construction of additional power plants to accommodate increased power demands.

Factor 4: Remaining Useful Life:

Generally the operational life of a catalyst is approximately 5 to 15 years, depending upon factors such as how it is maintained and the particular duty cycle of the engine.

Step 5: Select Reasonable Progress Control

The state has determined that control technology #3, rich burn NSCR w/air-fuel controller, represents reasonable progress for the natural gas-fired RICE source category in this planning period. The estimated reduction of 5,800 tons/year represents about 36% of the NG RICE total NOx emissions.

The State of Colorado regulates RICE under Colorado Air Quality Control Commission Regulation No. 7 (Reg. 7) Section XVII. Further NOx emission reduction benefits are anticipated in the future because of tighter NOx emission standards in Regulation 7 that require emissions from RICE shall not exceed the following emission performance standards:

Colorado Emission Standards Natural Gas-Fired RICE

RICE Horsepower	Construction or Relocation Date	Emission Standards (grams/hp-hr)		
		NO_x	CO	VOC
< 100	Any	NA	NA	NA
≥ 100 and ≤ 500	On or after 1/1/08	2.0	4.0	1.0
	On or after 1/1/11	1.0	2.0	0.7
> 500	On or after 7/1/07	2.0	4.0	1.0
	On or after 7/1/10	1.0	2.0	0.7

RICE that are subject to an emissions control requirement in a federal Maximum Achievable Control Technology (MACT) standard under 40 CFR Part 63, a Best Achievable Control Technology (BACT) limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to Reg. 7 Section XVII.

¹⁰ EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit OO: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin,
Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 –
Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying
Capability (ELCC) Study*, Public (Aug. 2, 2023)



Reserve Margin and Effective Load Carrying Capability (ELCC) Study

Final Report

8/02/2023

PREPARED FOR

Tri-State G&T

PREPARED BY

Astrapé Consulting

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ABBREVIATIONS USED IN REPORT

BAA	Balancing Authority Area
BE	Better Electrification
BESS	Battery Energy Storage System
BTMPV	Behind the meter solar
CEII	Critical Energy/Electric Infrastructure Information
CT	Combustion Turbine Generator
DR	Demand Response
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORD	Equivalent Forced Outage Rate Demand
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GDP	Gross Domestic Product
ICAP	Installed Capacity
ILR	Inverter Loading Ratio
IRP	Integrated Resource Plan
LFE	Economic Load Forecast Error
LOLE	Loss of Load Expectation
MW	Megawatt
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
ORDC	Operating Reserve Demand Curve
PCAP	Perfect Capacity
PO	Planned Maintenance Outage
PRM	Planning Reserve Margin
TTF	Time to Fail
TTR	Time to Repair
UCAP	Unforced Capacity
SAM	NREL System Advisory Model
SERVM	Astrape's Strategic Energy and Risk Evaluation Model

EXECUTIVE SUMMARY

This document provides details concerning a two-fold study performed by Astrapé Consulting for Tri-State Generation and Transmission Association (TSGT) to accomplish the following goals:

1. Determine the Planning Reserve Margin (PRM) for TSGT's 2023 Electric Resource Plan (ERP).
2. Determine the Effective Load Carrying Capability (ELCC) for a range of solar, wind, and Battery Energy Storage System (BESS) penetrations for the TSGT system.

The following summarizes the results of this study.

BASE CASE PRM RESULTS

The PRM of a system represents the amount of additional capacity in excess of forecasted peak load that a system would need in order to maintain an acceptable level of system reliability. The PRM was calculated using two different accounting methods, including:

1. ICAP – Traditional resources at Installed Capacity (ICAP) with renewable and other limited resources at their ELCC.
2. UCAP – Traditional resources at their Unforced Capacity (UCAP) with renewable and other limited resources at their ELCC.

The development of the PRM was accomplished by determining the amount of capacity that would be necessary to maintain a Loss of Load Expectation (LOLE) of 0.1 days/year. This level of reliability corresponds to an expectation of one day of loss of load every 10 years, which is consistent with industry practice. The advent of renewable and battery technologies has sparked conversation on the appropriateness of this metric since limitations on dispatchability and constraints on energy will likely affect the duration and depth of loss of load events. In prior work, Astrapé has found that renewable and storage resources generally have offsetting effects on the duration and depth of events and the 0.1 LOLE standard is expected to yield a relatively consistent relationship with most reliability metrics for a range of technology resource mixes. However, it will be important to continue to monitor these metrics and recommend changes to reliability standards if the nature of reliability events does change.

The PRM was developed using Astrapé's Strategic Energy and Risk Evaluation Model (SERVM). A detailed description of the methodology can be found in the Study Approach and Results section of this report. The PRM is the result of an evaluation of the probabilistically weighted LOLE across 42 weather year scenarios, five load forecast error scenarios, and hundreds of unit outage iterations. The PRM for the base case and most of the sensitivities were performed for the 2030 study year. The base case and its underlying assumptions are described in more detail in the Model Development section of this report.

Figure ES 1 below shows the result of the LOLE analysis for 2030. The figure shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE point occurs at a reserve margin of ~35.9%.

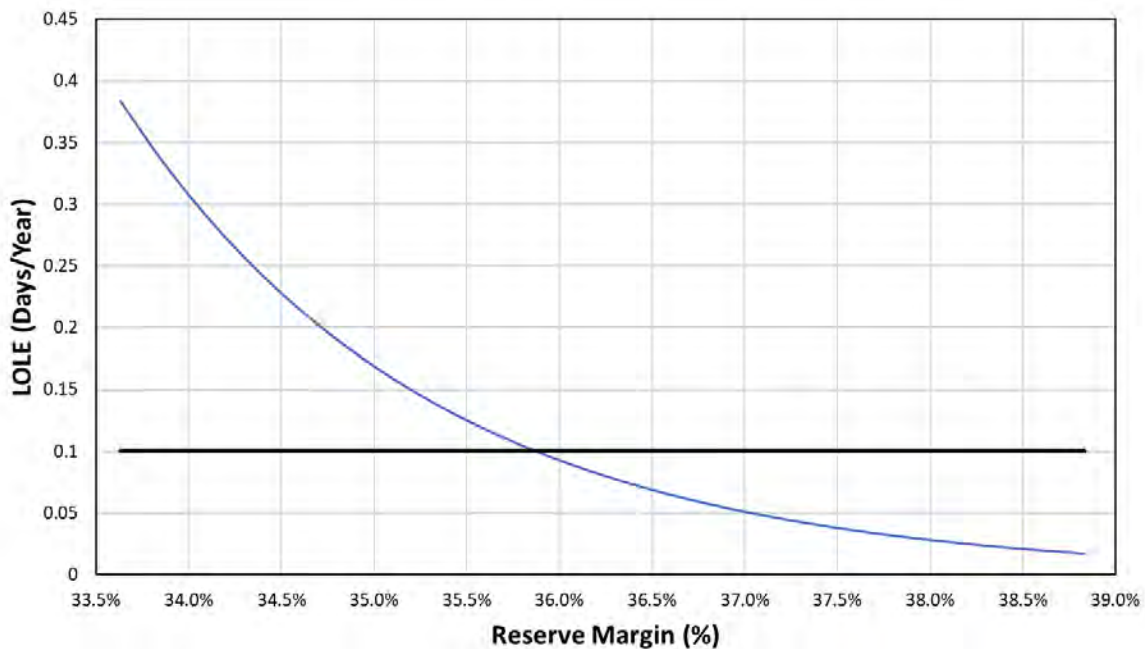


Figure ES 1. 2026 Base Case LOLE Analysis

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

The table below shows the ICAP accounting for the base case scenario.

Table ES 1. Base Case ICAP PRM Accounting

Component	Capacity	ELCC	Equivalent Capacity
Conventional Resources	2596.3		2596.3
ELCC Resources	1934.0	18%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			3003.6
Coincident Peak Load			2210.9
Reserves			792.8
ICAP PRM			35.9%

The “Adjustment Capacity” represents the amount of additional capacity above base case assumptions that was added to the system to achieve the 0.1 LOLE requirement. The ICAP PRM of 35.9% is considerably higher than TSGT’s previous requirement of 15% for several reasons. First, in the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Second, TSGT will be losing approximately one-third of its load over the next few years as several member systems leave the system or transition to partial requirements. The result is a considerably smaller system in which shaft risk (i.e., the loss of units that are large relative to the peak load) becomes a more significant consideration than it was in the past. For example, with a prior peak of ~3000 MW the Springerville unit covered 14% of the load requirements. With a reduced peak of ~2200 MW, Springerville is now covering 19% of the load. Thus, more load is concentrated on that single unit, resulting in an increase in shaft and generation risk if that unit trips or fails. A similar issue is present for the other larger units, compounding the potential shaft risk in 2030. While there may have been shaft risk previously, that risk has been magnified by the loss in peak demand. The increased shaft risk translates directly into higher PRM requirements.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system Equivalent Forced Outage Rate (EFOR) resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. An alternative accounting that attempts to stabilize the PRM by removing the effects of forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by $1 - \text{EFOR}_d$, where EFOR_d is the Equivalent Forced Outage Rate Demand for the conventional resources. The table below shows the base case assuming UCAP accounting resulting in a UCAP PRM of 30.5%.

Table ES 2. Base Case UCAP PRM Accounting

Component	Capacity	UCAP/ ELCC	Equivalent Capacity
Firm Resources			997.3
UCAP Resources	1599.0	92.6%	1480.1
ELCC Resources	1934.0	18.0%	348.1
Adjustment Capacity			59.2
Total Reliable Capacity			2884.6
Coincident Peak Load			2210.9
Reserves			673.8
ICAP PRM			30.5%

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and are achieved with identical portfolios. The only difference is in the accounting treatment of various resources.

As part of the base case PRM calculation, the ELCC of the conventional resources were calculated to demonstrate the significance of the shaft risk. The table below shows the ELCC of the coal and CC units.

Table 1. Coal and CC ELCC

Resource	EFOR	ELCC
Shafer CC	7.8%	64.4%
Springerville Coal	9.2%	63.8%
Laramie River Coal	9.3%	58.8%

These ELCCs are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

Table 2. Impact of High EFOR and Shaft Risk

Component	ELCC	MW	Impact
CC	64.4%	272	175.168
SPV	63.8%	319	203.522
LRS	58.8%	484	284.592
Weighted	61.7%	1075	663.282
Target ELCC	90.0%	1075	967.5
Impact MW			304.2
Base Case Reliable MW			3003.6
Adj for EFOR/Shaft Impact			2699.4
Coincident Peak Load			2210.9
PRM			22.1%

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

The lower ICAP PRM of 22.1% would represent a system in which shaft risk and high EFOR has been somewhat mitigated. Since the two drivers of this increased shaft risk are the retirement of several

coal units and the departure of approximately one-third of TSGT's peak demand, it would be reasonable to assume that a transitional PRM in this range would be appropriate to use for the transition years prior to the retirement of those units and the departure of the member load.

ELCC RESULTS

The ELCC of a renewable resource/portfolio represents the amount of dependable capacity that can be counted on by the system for resource adequacy purposes and the resource's perfect capacity equivalent. The ELCC is determined by finding the amount of perfect capacity that can replace the renewable resource/portfolio without adversely affecting system reliability. The ELCC is represented as a percent of nameplate capacity. It is calculated by dividing the amount of replacement perfect capacity by the nameplate capacity of the additional renewable resource/portfolio.

For ICAP and UCAP PRM accounting purposes, the ELCC of the base case portfolio of solar and wind resources was calculated. Those results are shown in the applicable ICAP/UCAP tables in the PRM results sections above and reflect a portfolio average ELCC of 18%.

The analysis also included the calculation of average and marginal ELCCs by technology for solar, storage, and wind up to the following maximum penetrations:

- Solar – 2,000 MW
- Battery – 1,000 MW
- Wind – 2,000 MW

The result of this analysis was a dense, three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the maximum penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

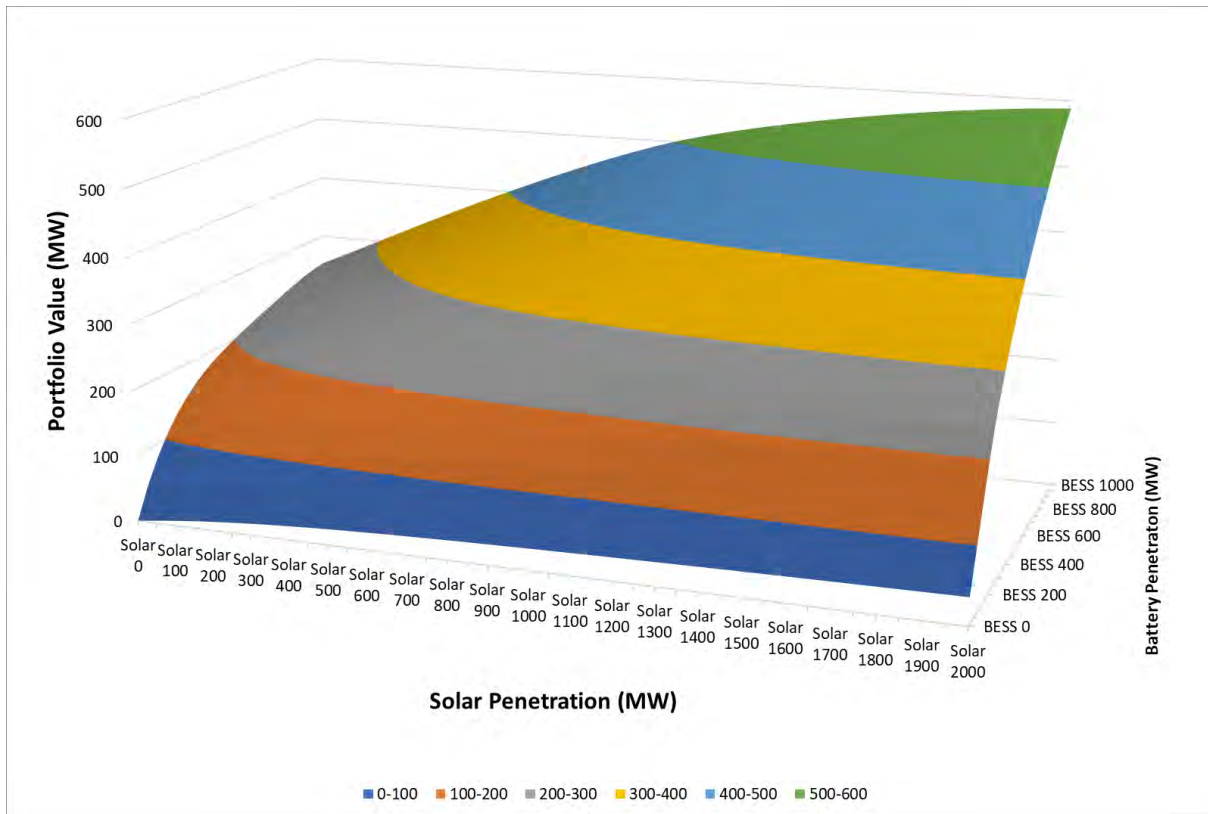


Figure 1. Portfolio Capacity Value at Zero Wind Penetration, Illustrative

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind:

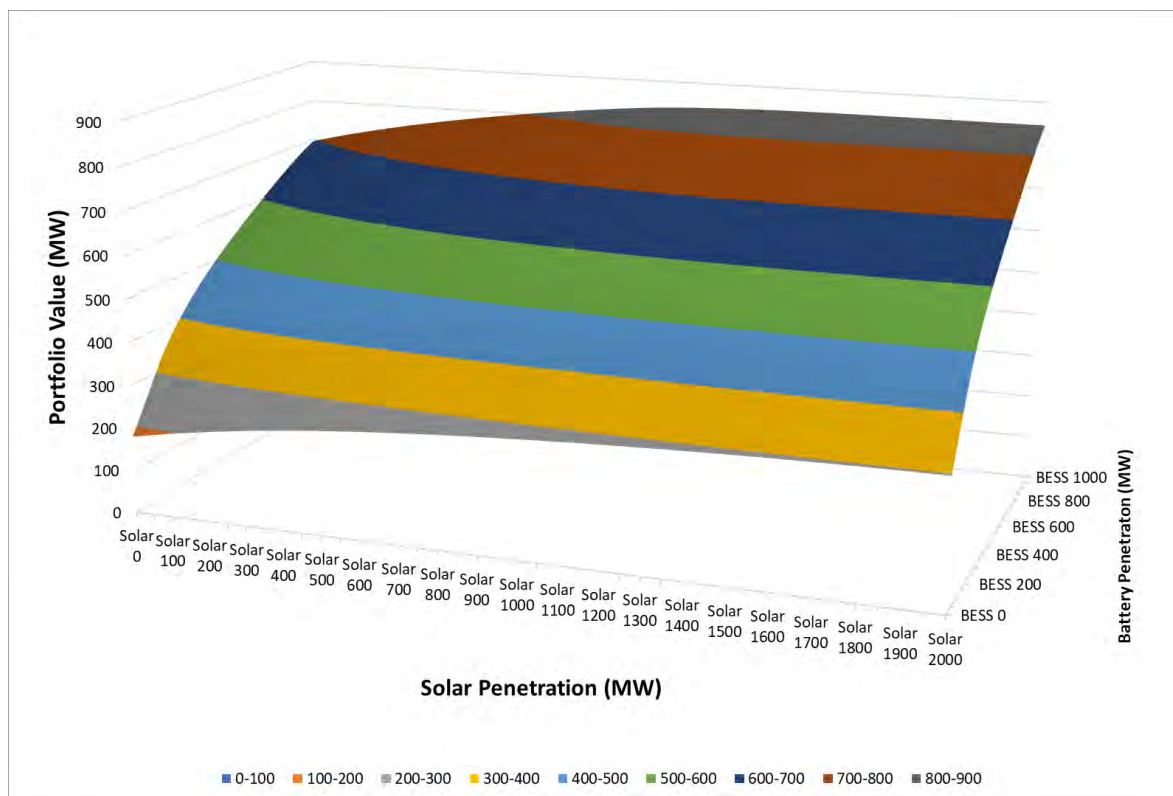


Figure 2. Portfolio Capacity Value at 2000 MW of Wind, Illustrative

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries (i.e., in the solar chart, wind is at 1,000 MW and batteries are at 500 MW, whereas in the battery chart, solar and wind are both at 1,000 MW).

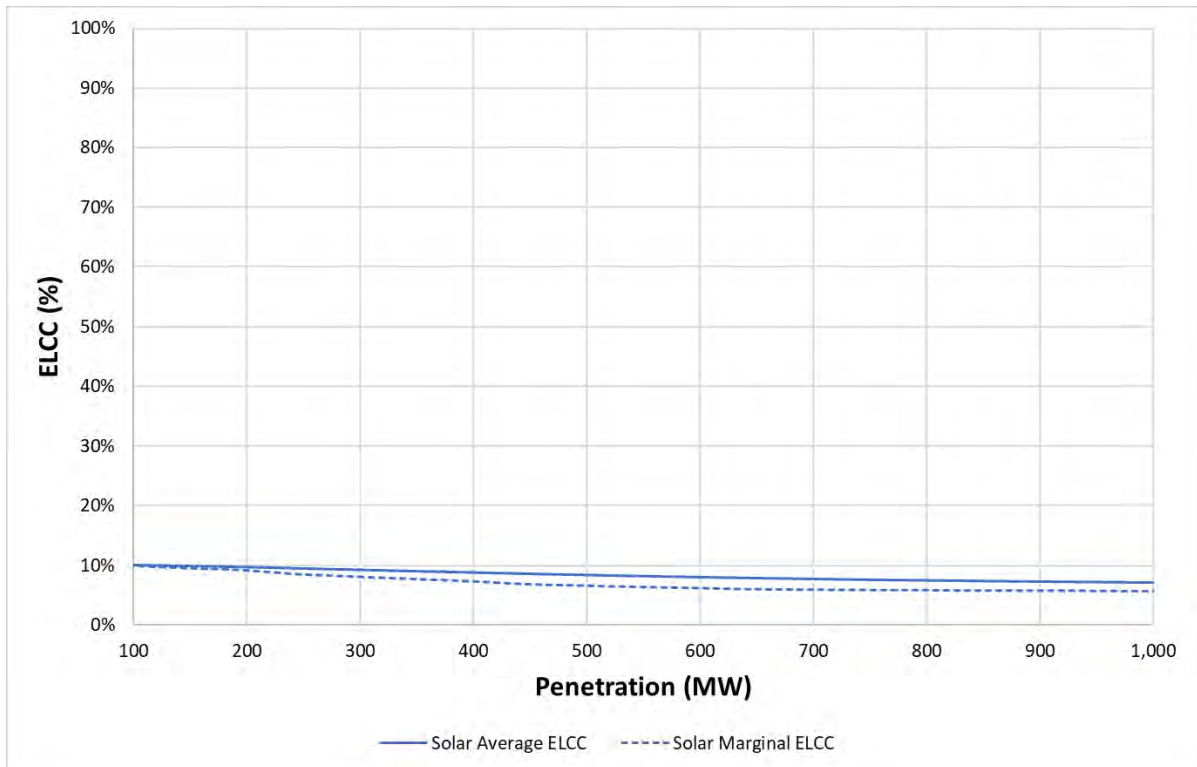


Figure 3. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

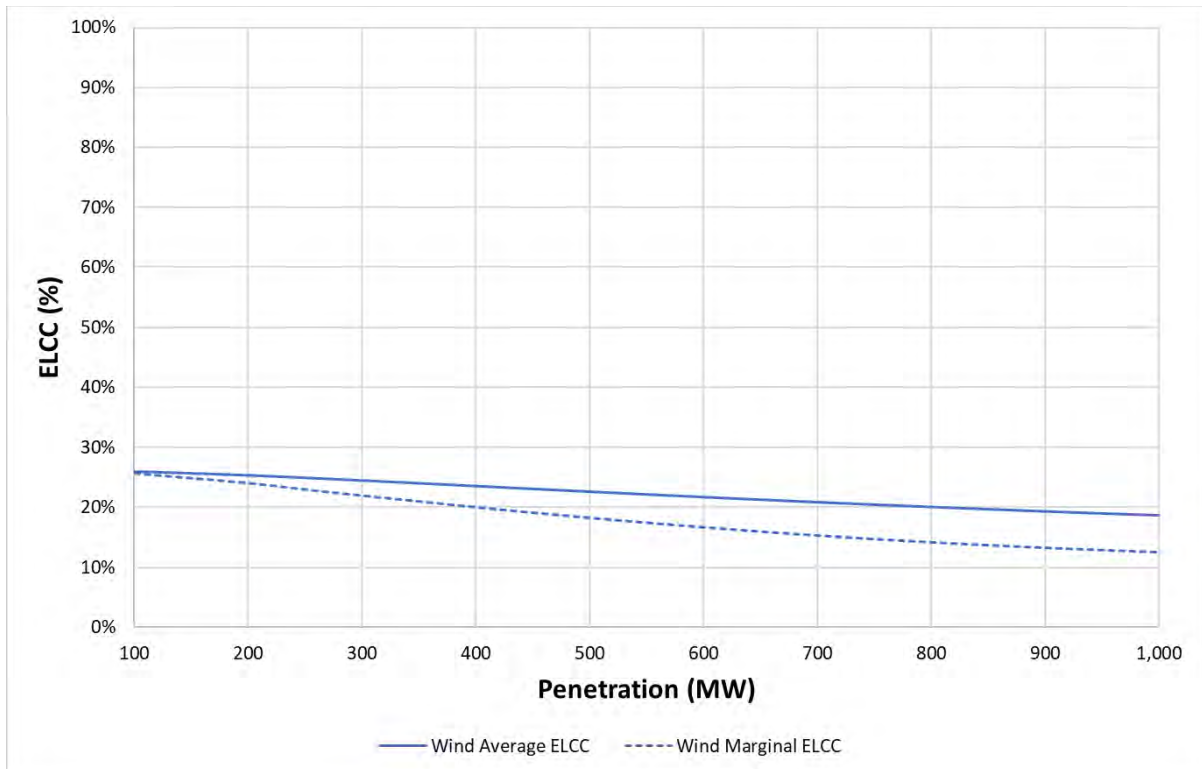


Figure 4. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery

Finally, the battery chart is shown below.

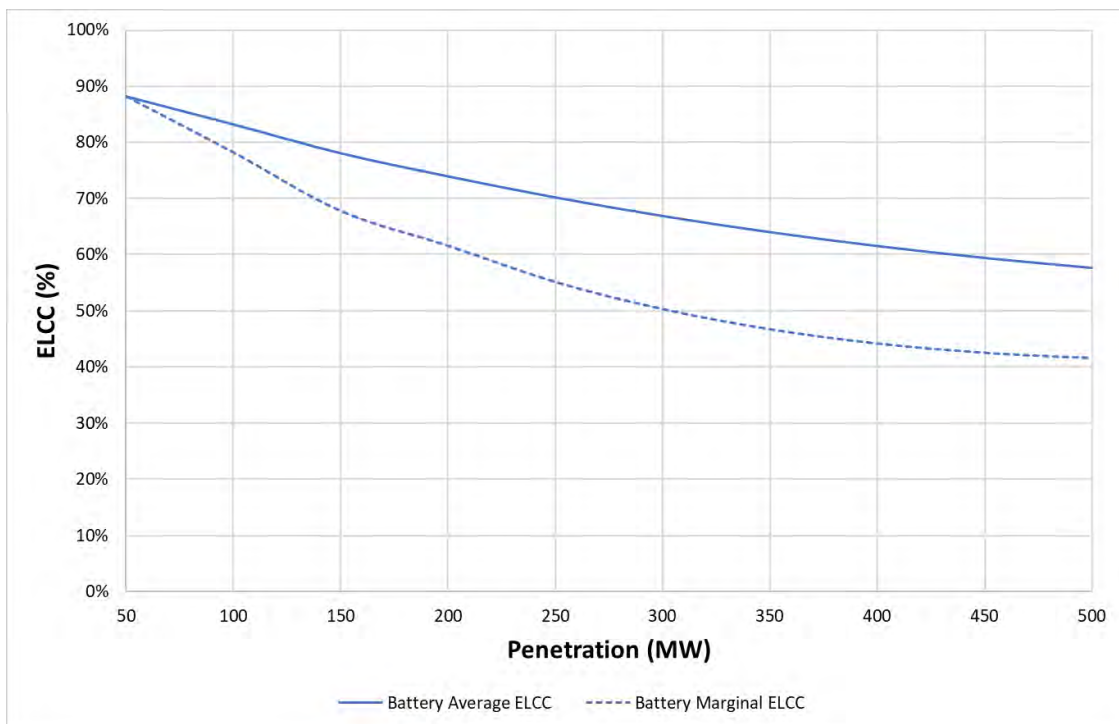


Figure 5. Battery ELCC at 1,000 MW of Solar and Wind

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including member system DG (not rooftop) solar, EE, and 10-hour batteries.

To determine the ELCC of the member system DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the member system DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be “first in the queue” relative to the TSGT solar. Since entity-specific capacity accreditation is not an issue for TSGT, the only concern is to get the appropriate total portfolio capacity credit for purposes of counting capacity towards meeting the reserve margin requirement. Therefore, it does not matter whether all renewable resources are considered to be added simultaneously or as was done in this analysis, some renewables were presumed to have a “first in the queue” status.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The result of this analysis is shown in the figure below.

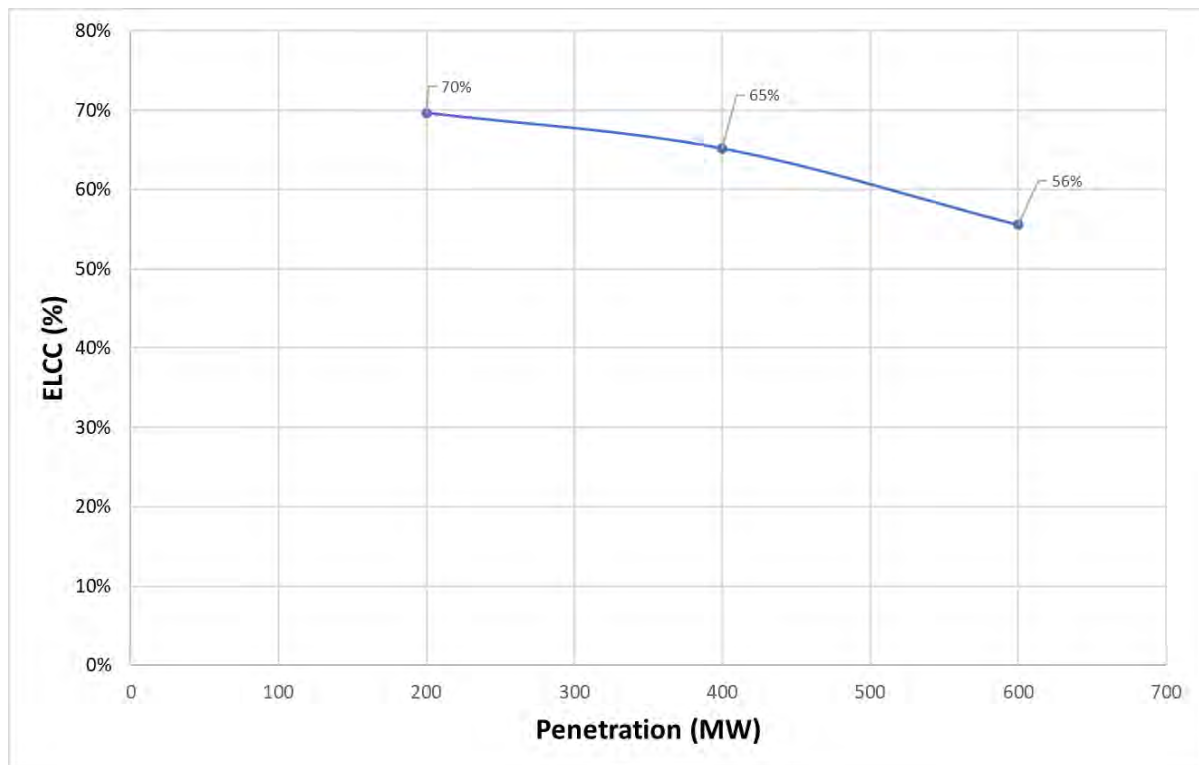


Figure 6. 10-Hour Battery Average ELCC

CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

INTRODUCTION

The purpose of this document is to describe the analysis used to determine the PRM necessary for TSGT to maintain a LOLE of 0.1 days/year or the equivalent of the common industry practice of one loss of load event in 10 years.

In addition, this document will also report on the results of a study to determine the ELCC of a series of tranches of solar, wind, and BESS resources – as well as the ELCC of several other load and resource components including customer DG solar, EE, and long duration (10-hour) batteries.

STUDY FRAMEWORK

This study was performed using the SERVVM and its associated study framework. The SERVVM framework combines an hourly (i.e., 8760-hour) production cost model coupled with Monte Carlo outage simulation and comprehensive scenario management that considers load and weather uncertainty to determine key reliability parameters such as LOLE. The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

WEATHER UNCERTAINTY

To account for weather uncertainty, SERVVM performs hourly production cost simulations using multiple historical weather years. The uncertainties that are modeled for each modeled weather year include load shapes and renewable profiles. Load shapes for each weather year are developed to represent the expected future load response to the historical weather (temperatures). For example, a 1998 weather year represents how loads would respond if 1998 weather were to repeat during the given study year. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. In the case of TSGT, since their load forecast is based on the last 10 years of history, load shapes are scaled such that the median of the last 10 years equals the study year weather normal peak load forecast. Other load shapes were scaled such that their forecast matched the median of all available weather years. Similarly, renewable profiles are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 42 weather year scenarios were simulated representing weather conditions for the years 1980-2021.

ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather normal peak load forecast associated with uncertainty in economic forecasts. Using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP), it is possible to predict both the magnitude and probability of error in the forecast of the GDP economic indicator three, four, or five years out into the future. This probability of error can then be converted into a Load Forecast Error (LFE). For this study, five LFE scenarios were chosen. These are described in the Model Development section of this document. Each of the 42 weather year scenarios are combined with each of the five LFE scenarios to create 210 unique load scenarios, or *cases*.

MONTE-CARLO OUTAGE ITERATIONS

SERVM uses Monte-Carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 210 load cases. With each outage iteration, random Monte-Carlo draws are made to determine thermal generation outage profiles associated with that scenario. With enough iterations, the set of random outages for each thermal unit approaches that unit's expected EFOR. For this study, convergence was achieved with 200 outage draw iterations per case. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVVM uncertainty framework used for this study required 42,000 hourly (8760-hour) production cost simulations for a single analytical run of the TSGT system.

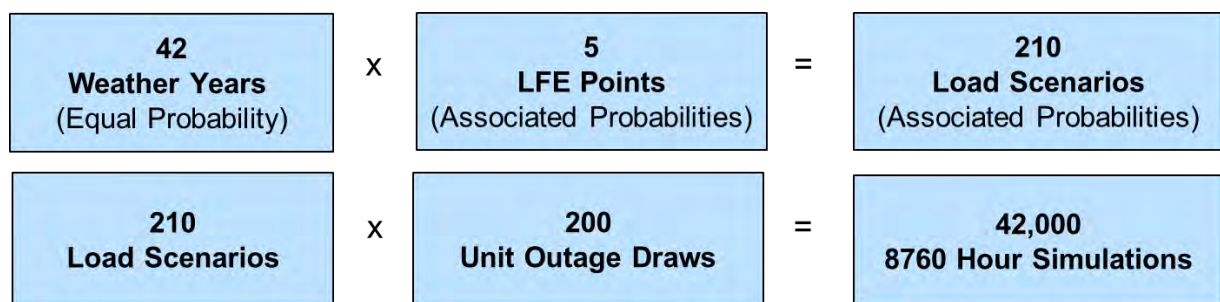


Figure 7. SERVVM Uncertainty Framework

The Study Methodology section of this document describes the numerous “analytical runs” required to perform the reserve margin analysis, its associated sensitivities, as well as the ELCC analysis.

MODEL DEVELOPMENT

The SERVIM data model utilized for this study was based upon a joint dispatch of the four Tri-State load zones in the Western Area-Colorado Missouri (WACM), Public Service Colorado (PSCO), and Public Service New Mexico (PNM) Balancing Authority Areas (BAA). Those four load zones are Tri-State New Mexico (Tri-NM), Tri-State West Colorado (Tri-WCO), Tri-State East Colorado (Tri-ECO), and Tri-State Wyoming-West Nebraska (Tri-WYNE). The system model also included representations of the immediate surrounding interconnected BAAs, including representations of the balance of each of the three before-mentioned BAAs, PacifiCorp East (PACE), Arizona (AZ),¹ and Southwest Public Service (SPS), which is in the Southwest Power Pool (SPP).² The figure below shows the configuration of the study model.

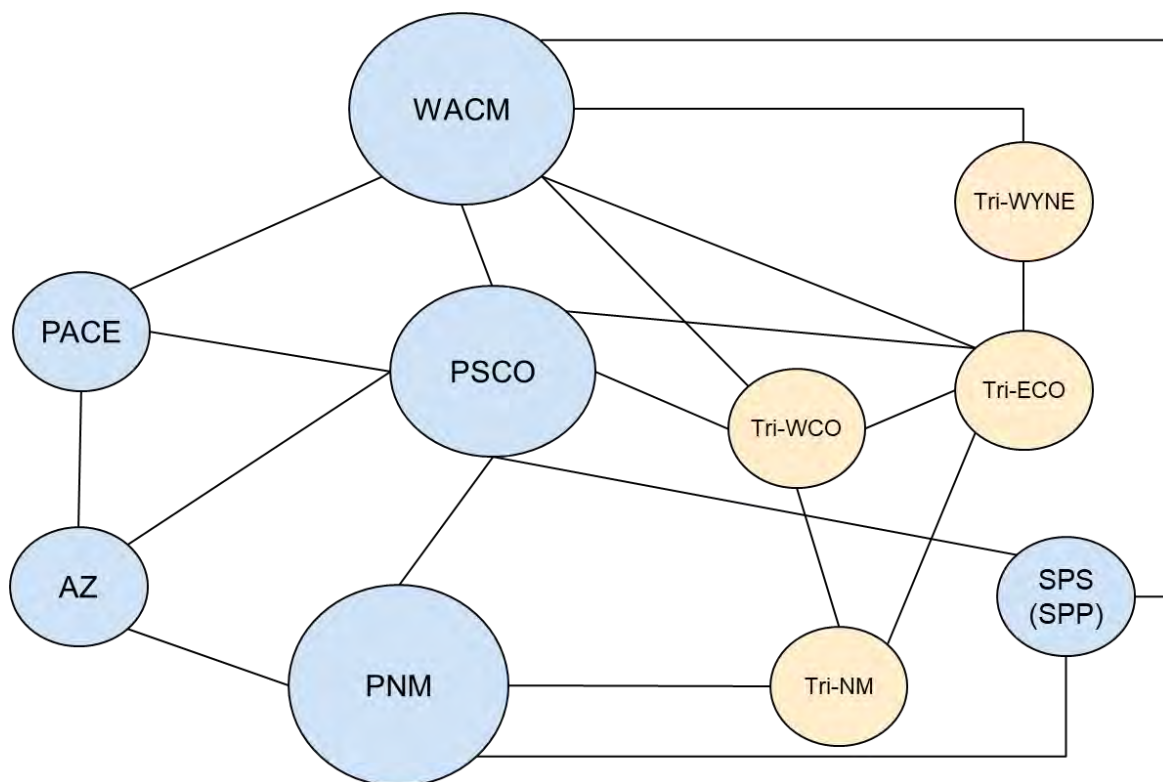


Figure 8. System Topology

BASE CASE MODEL DEVELOPMENT

For the Non-TSGT regions, the SERVIM database was developed using publicly available data from sources such as the U.S. Department of Energy's Energy Information Administration (EIA) Form 860, available documents from the North American Reliability Corporation (NERC), various publicly available Integrated Resource Plans (IRPs), and Federal Energy Regulatory Commission (FERC) Forms.

¹ This includes all of the entities in the Arizona Public Service BAA.

² SPS is across the DC ties between the Eastern Interconnect and the Western Interconnect.

The TSGT region, however, was updated using information provided by TSGT as described in the following sections.

PEAK DEMAND FORECAST

TSGT is a wholesale provider of power to members systems consisting of rural electric cooperatives and public power districts. The TSGT official load forecast is developed based on the load from these retail service providers net of adjustments for rooftop solar resources (BTMPV). For this study, these BTMPV resources were modeled as specific resources. Additionally, incremental energy efficiency (EE) was modeled as an explicit hourly load modifier. Therefore, the TSGT forecast, which was already grossed up for incremental EE, had to be further grossed up for the impacts of the BPMPV. The figure below shows the 2030 TSGT peak demand forecast as well as the grossed up peak demand forecast used for base case modeling purposes for each of the four TSGT load zones.

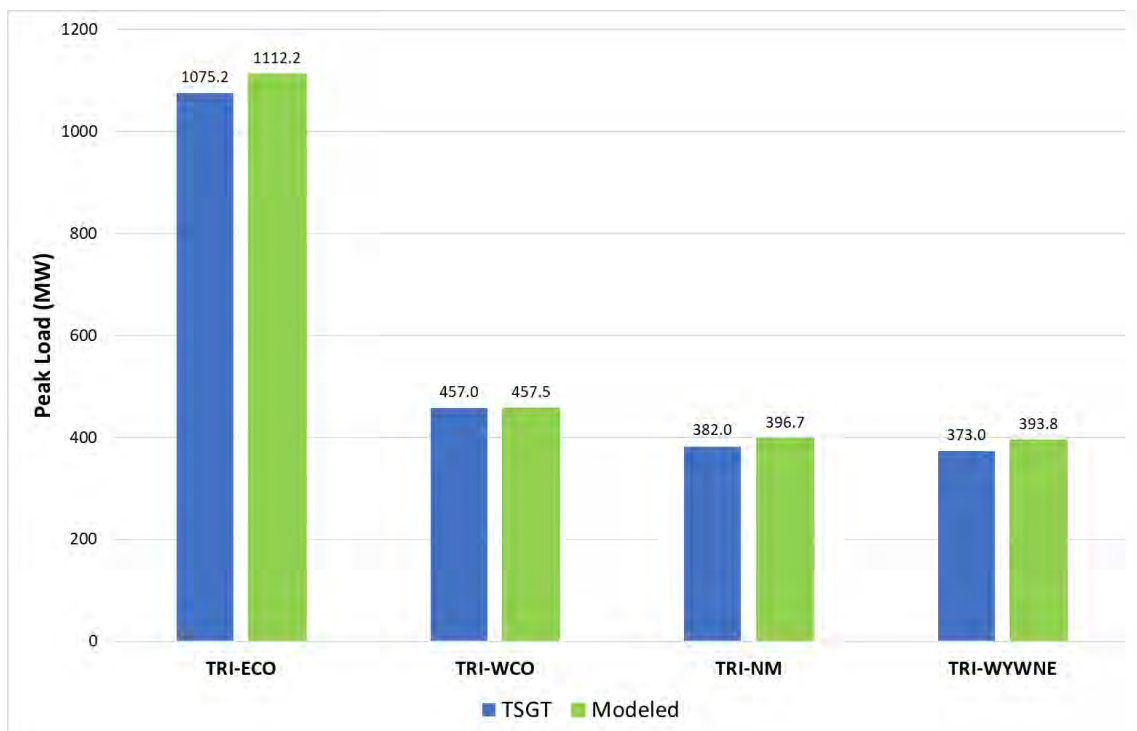


Figure 9. 2030 Peak Demand Forecast

The figure below shows the 2030 TSGT energy forecast as well as the grossed-up energy forecast used for modeling purposes.

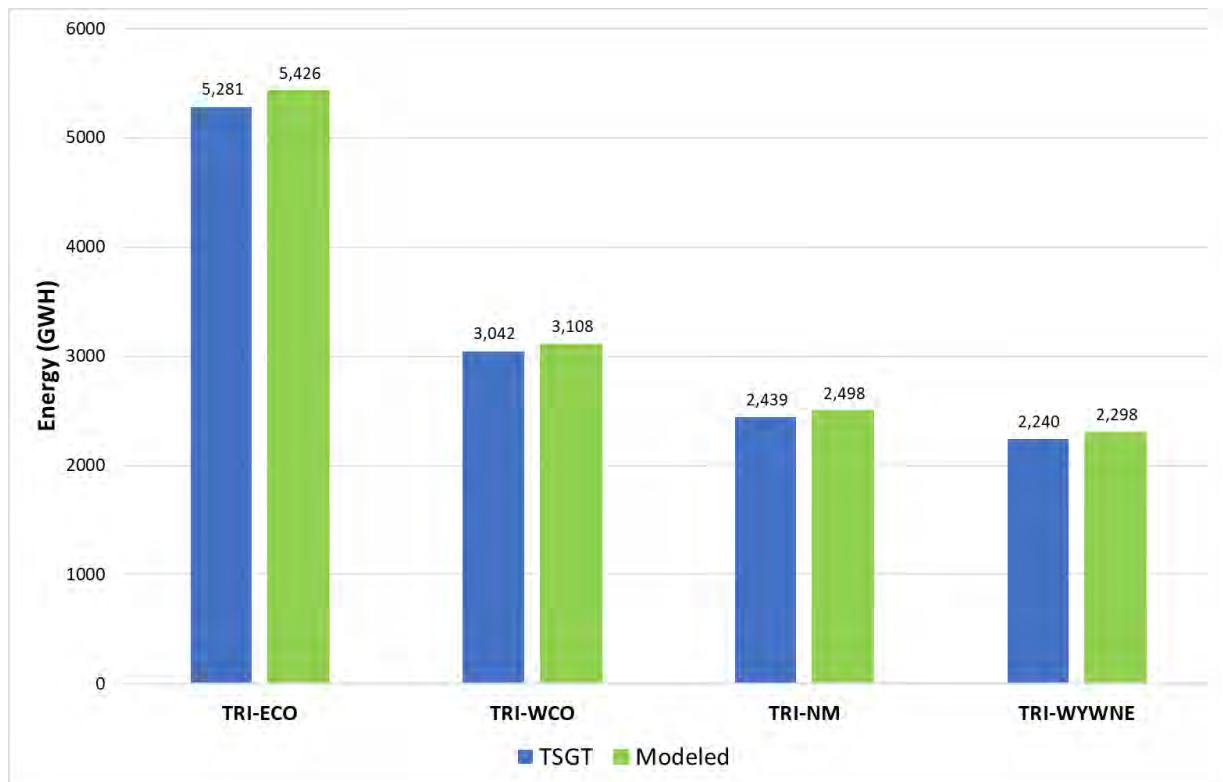


Figure 10. 2030 Energy Forecast

LOAD MODELING

As described in the Study Framework subsection above, load shapes were developed for each of the 42 study years 1980-2021. These load shapes were developed based on trends and relationships between load and weather for the five historical years 2018-2022.

To prepare the loads for trending, the historical loads were grossed up for BTMPV as indicated above. The loads were further prepared by removing economic bias as well as impacts of irrigation load uncertainty. These differences were removed from the load shapes by adjusting the loads on a seasonal basis so that the highest load hours of each season were consistent across the historical period. The figure below shows an example of the result of this process. The figure shows summer weekday loads during for the Tri-WYWNE load region for hours 13-17 when temperatures were above 85°F. Loads have been adjusted to remove economic bias.

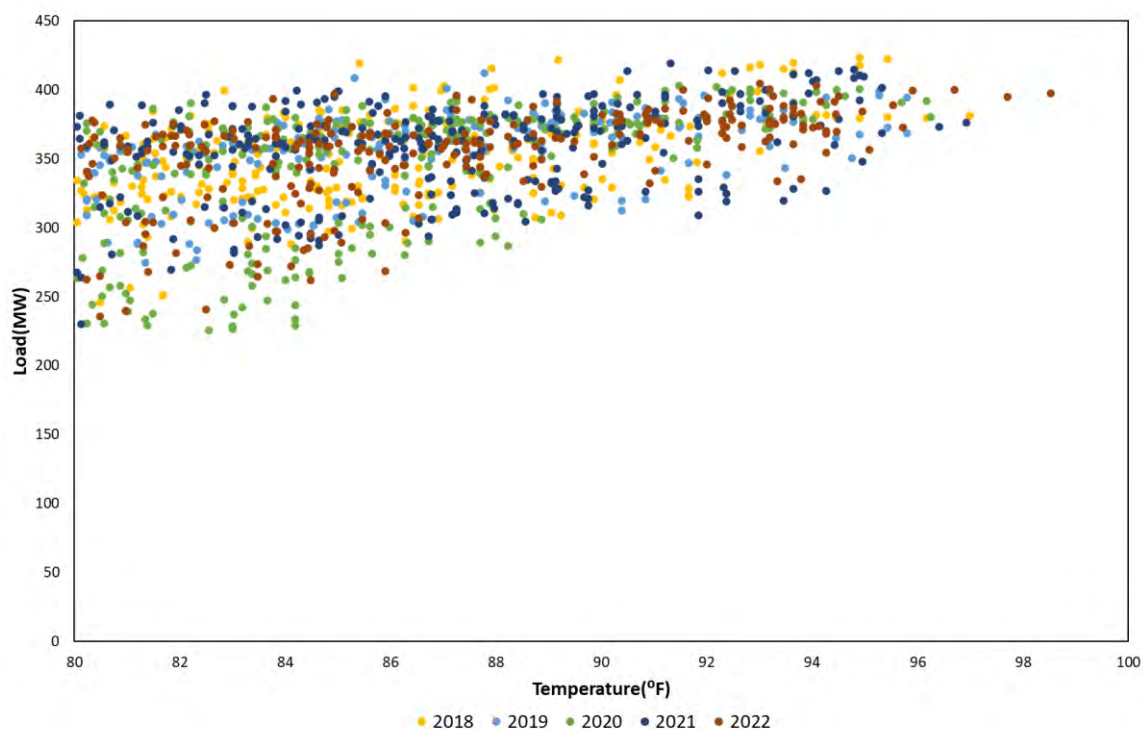


Figure 11. Summer Peak Period Temperatures

The five historical load shapes were trended using a neural network that was trained using hourly historical temperatures from the National Oceanic and Atmospheric Administration (NOAA) and other key variables. For trending purposes, temperatures from NOAA were downloaded for the period 1980-2022. However, because TSGT loads are located in more rural locations, historical temperatures were often unreliable or unavailable. Therefore, it was often necessary to use a nearby metropolitan area as a proxy for the temperatures for the TSGT loads.

Tri-ECO temperatures were based on the following locations and weightings:

- Denver – 55.4%
- Ft. Collins – 25.7%
- Colorado Springs – 7.85%
- Trinidad – 6.9%
- Pueblo – 3.9%
- Cheyenne – 0.3%

Tri-WCO temperatures were based on the following locations and weightings:

- Denver – 27.5%
- Ft. Collins – 14.5%
- Durango – 38.8%
- Grand Junction – 19.1%

Tri-NM temperatures were based on the following locations and weightings:

- Albuquerque – 41.1%
- Las Cruces – 43.9%
- Pueblo – 15%

Tri-WYWNE temperatures were based on the following locations and weightings:

- Cheyenne – 41.4%
- Casper – 58.6%

In addition to temperature, the neural net was provided with training variables that included day of week, hour of day, hour of week, 8-hour rolling average temperature, 24-hour rolling average temperature, and 48-hour rolling average temperature. “Networks” were created for Winter, Summer, and Shoulder periods. These trained networks were then applied to the NOAA weather data for the historical years 1980-2021 to develop synthetic load shapes for each of the 42 weather years.

Since the 42 years of historical weather data contains temperature data outside the range of that contained in the historical load set used to train the neural networks, those values were determined using peak load regressions developed outside the neural network. Peak load regressions were developed for summer afternoon, winter morning, and winter afternoon periods. These adjustment regressions were only applied to days in which the temperature fell outside the reasonable range of the 5-year historical data set. The figures below show the regressions performed for each of those three periods for each of the four TSGT load zones.

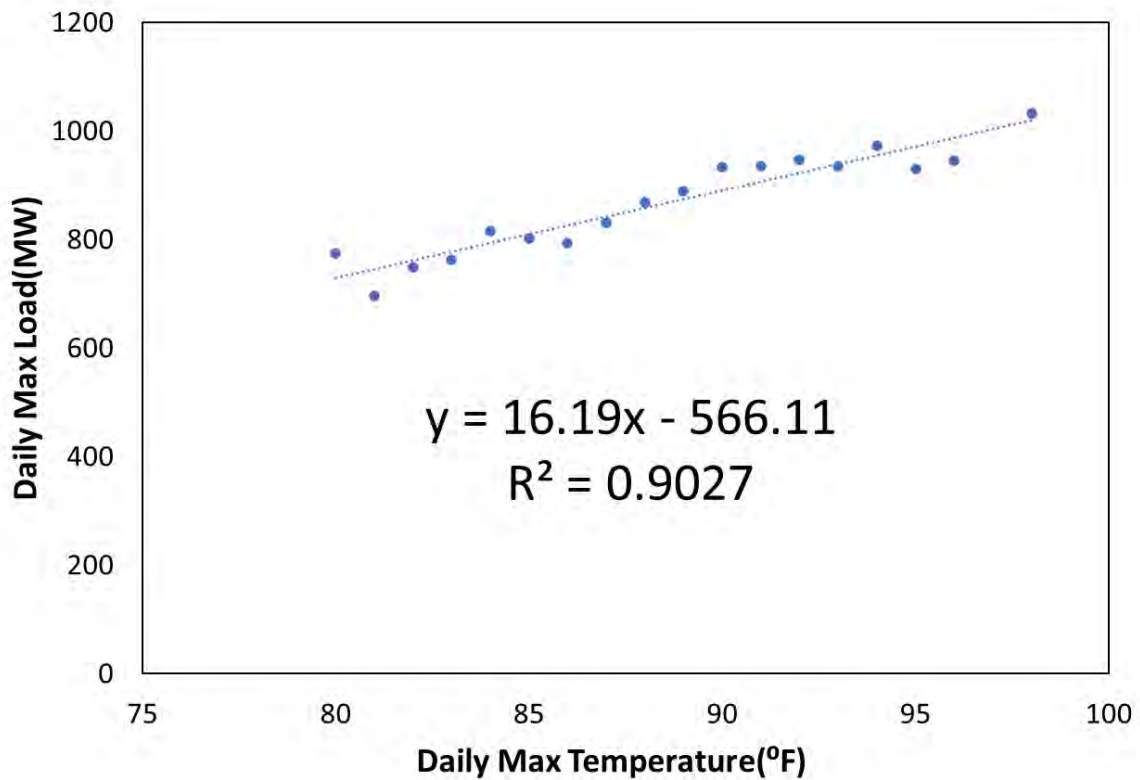


Figure 12. Tri-ECO Summer Afternoon Extreme Temperature Regression

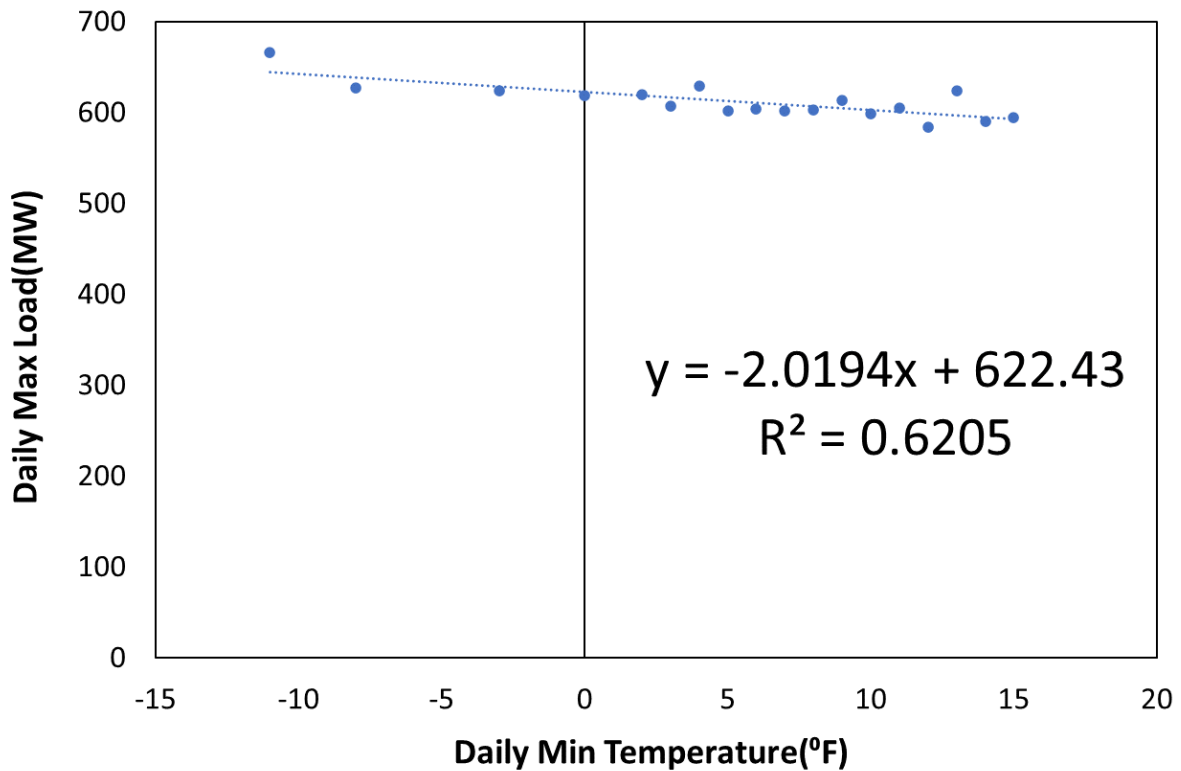


Figure 13. Tri-ECO Winter Afternoon Extreme Temperature Regression

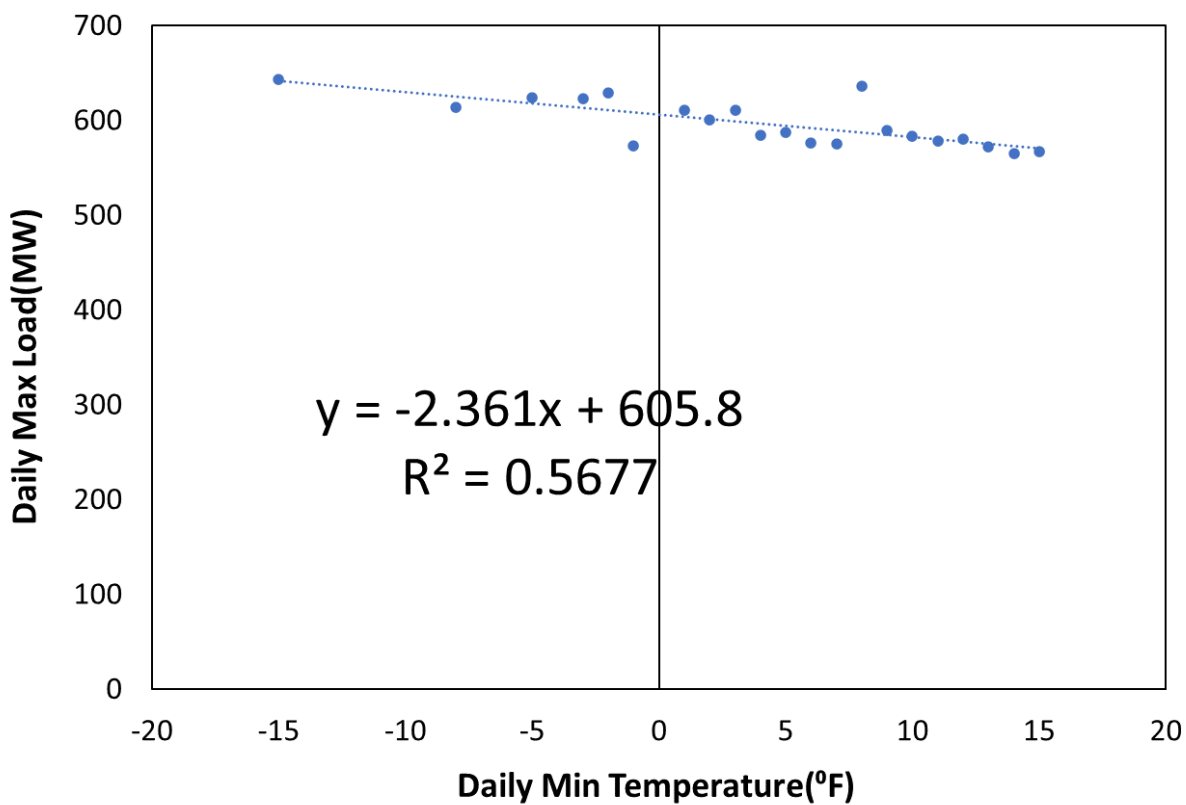


Figure 14. Tri-ECO Winter Morning Extreme Temperature Regression

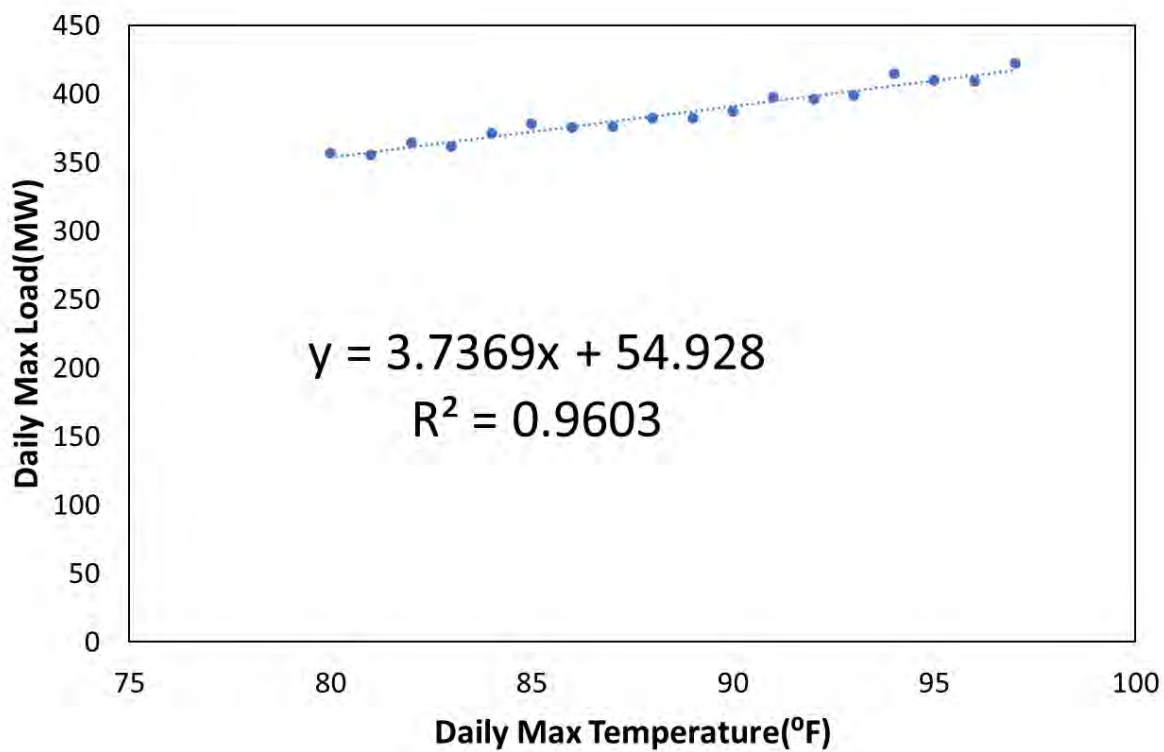


Figure 15. Tri-WCO Summer Afternoon Extreme Temperature Regression

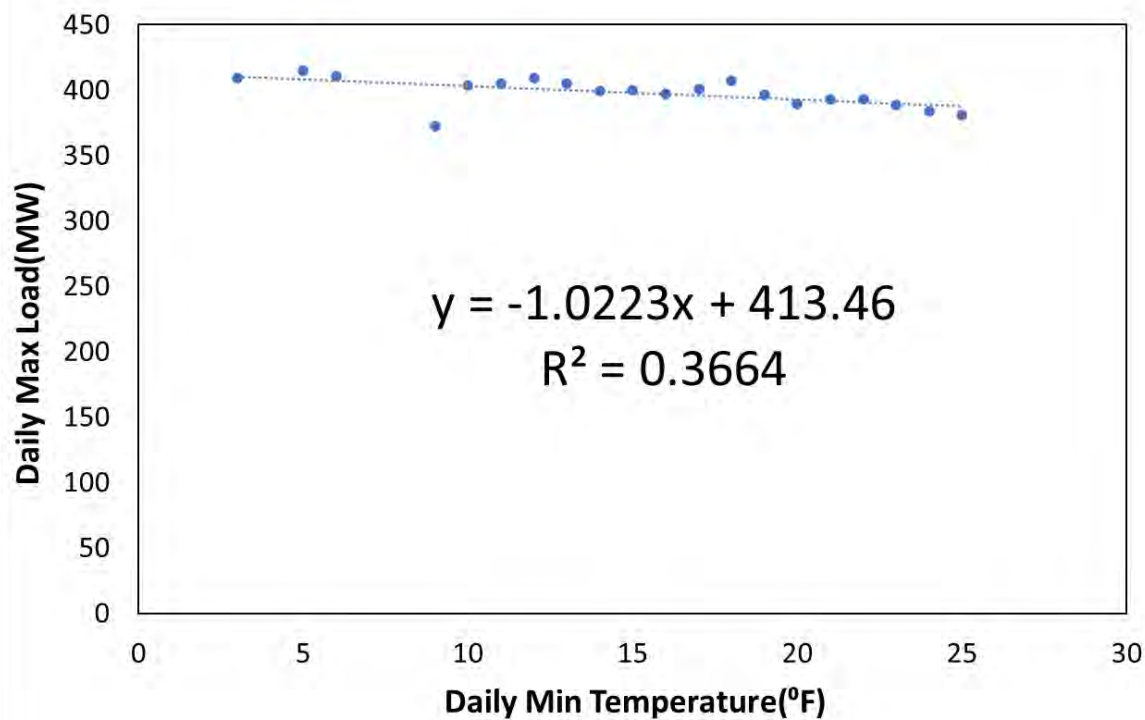


Figure 16. Tri-WCO Winter Afternoon Extreme Temperature Regression

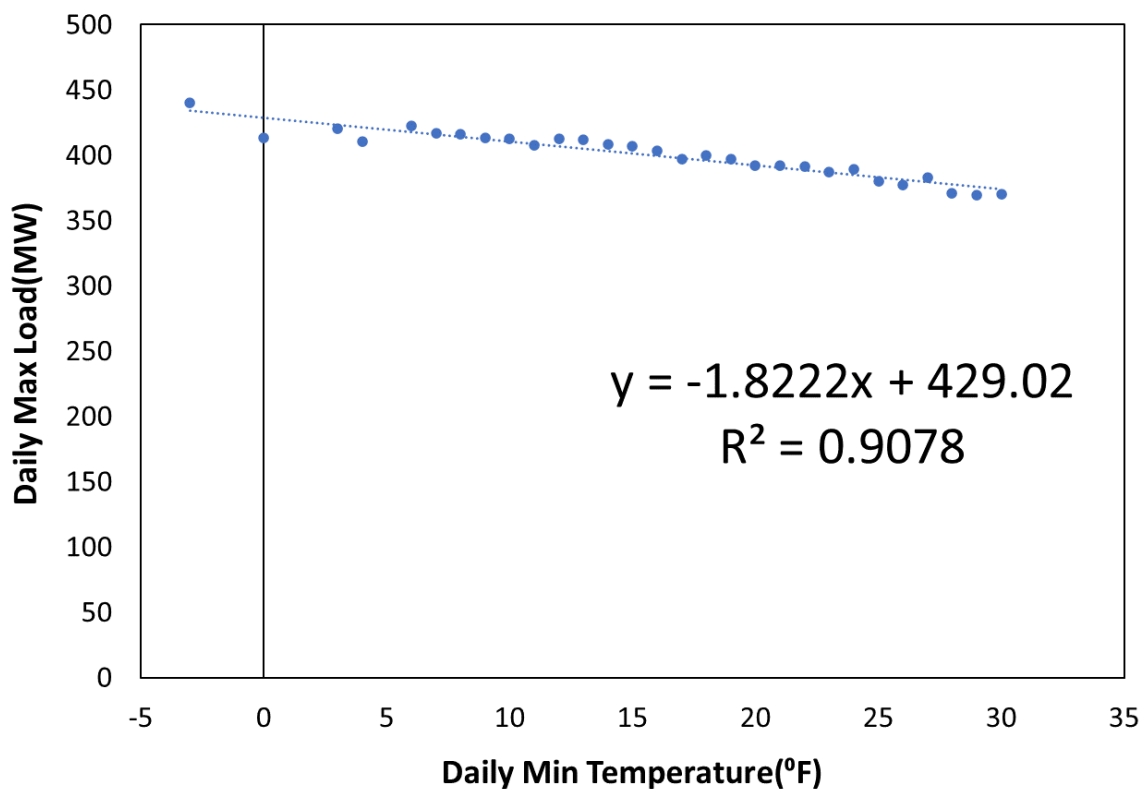


Figure 17. Tri-WCO Winter Morning Extreme Temperature Regression

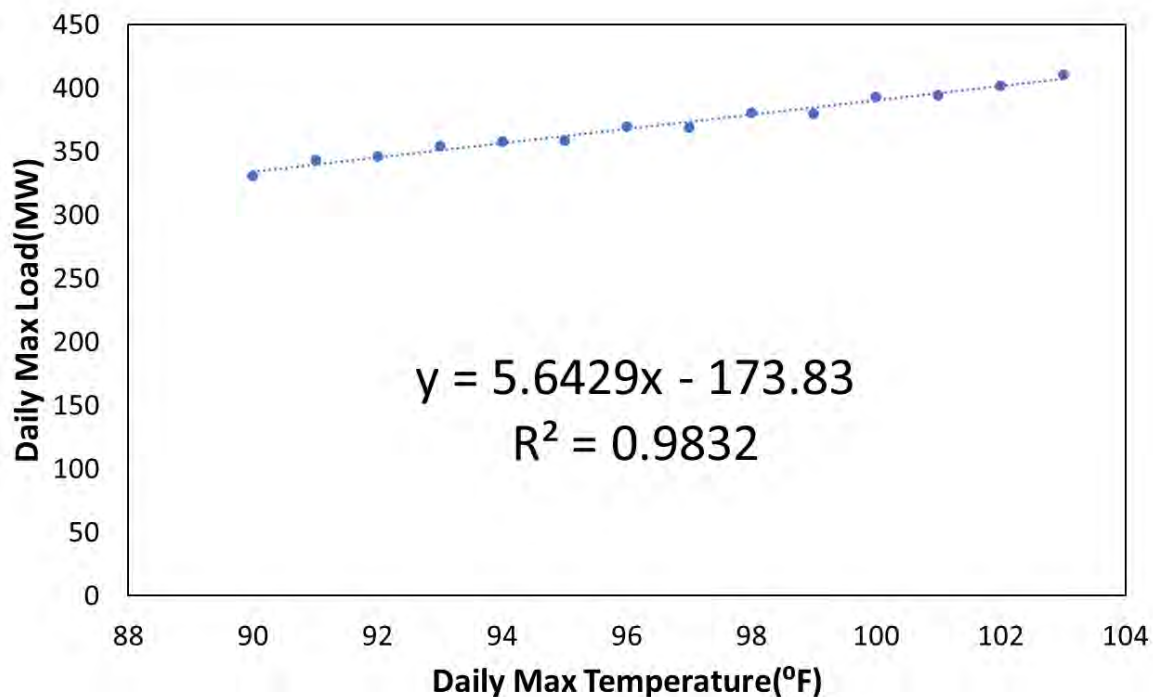


Figure 18. Tri-NM Summer Afternoon Extreme Temperature Regression

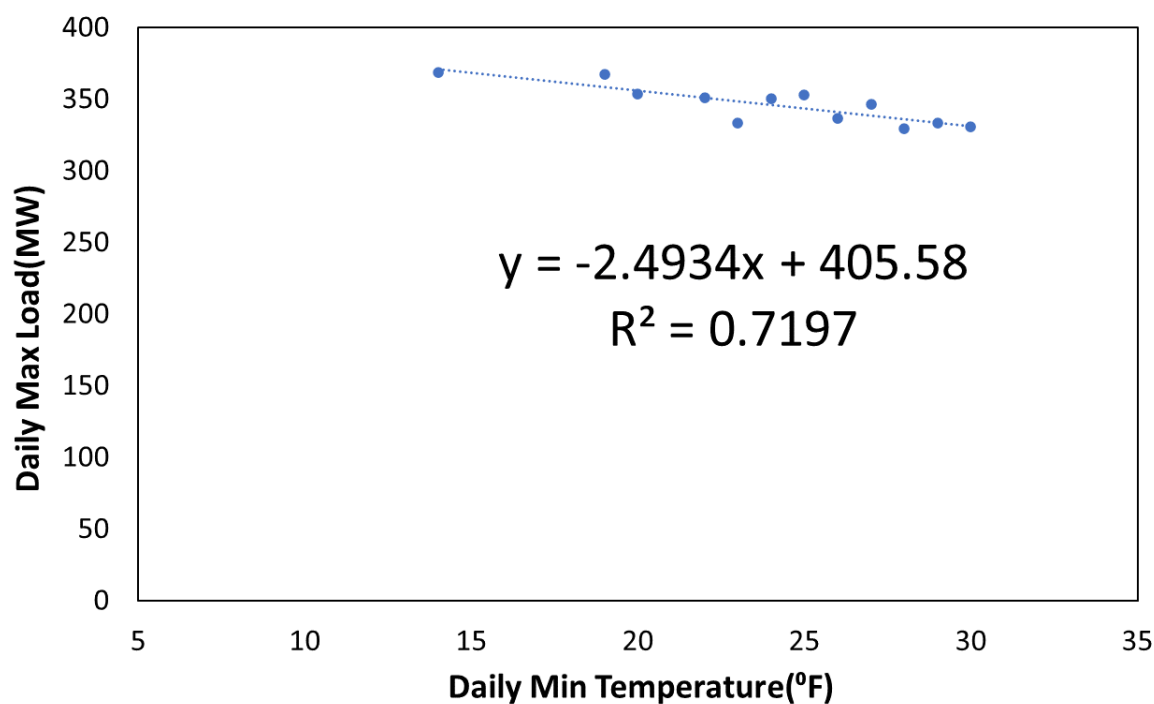


Figure 19. Tri-NM Winter Afternoon Extreme Temperature Regression

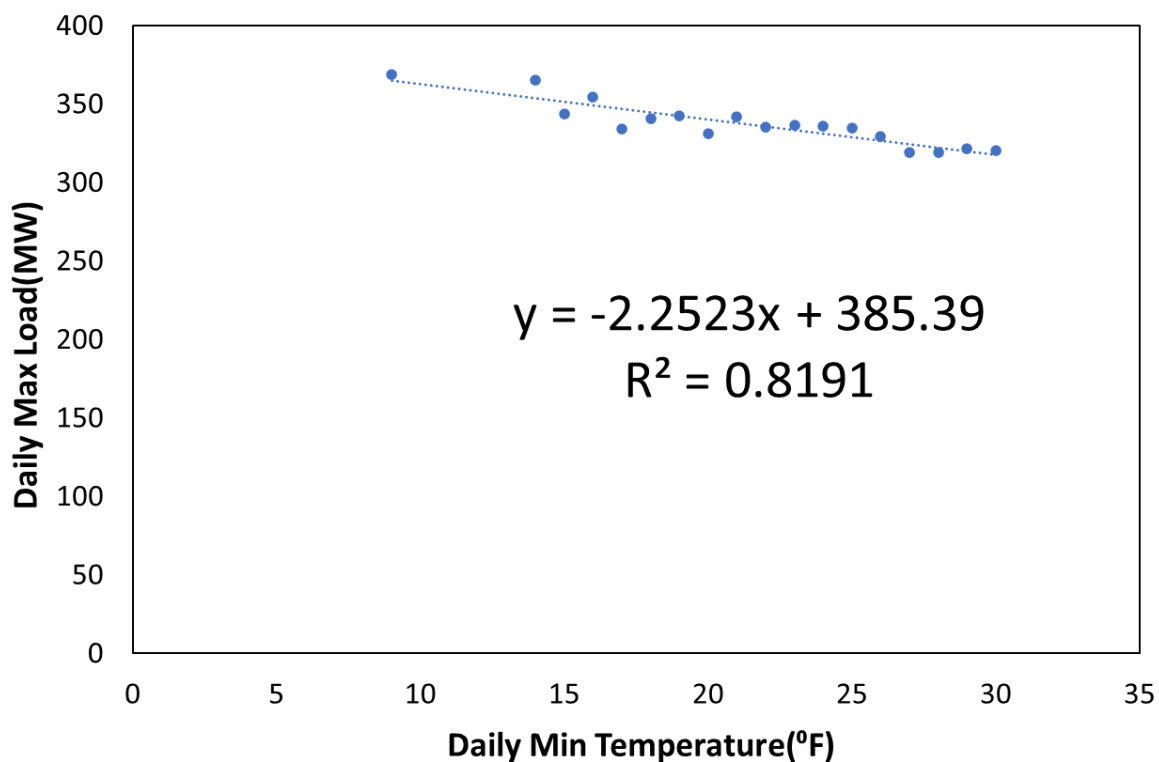


Figure 20. Tri-NM Winter Morning Extreme Temperature Regression

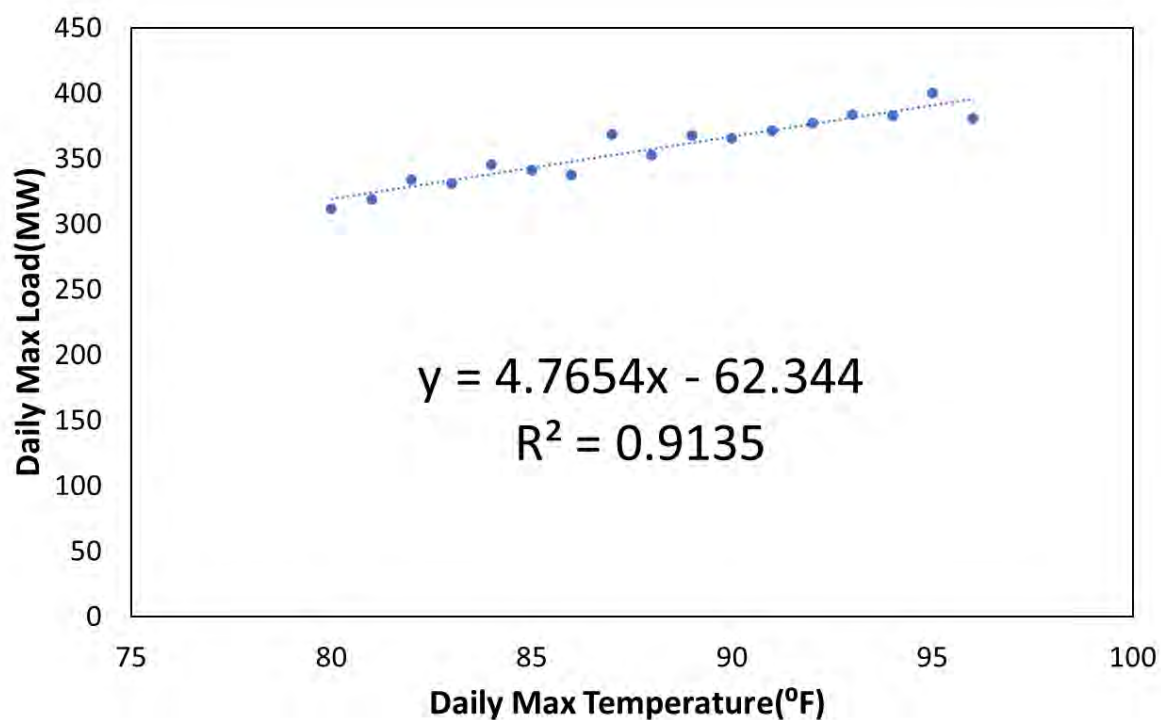


Figure 21. Tri-WYWNE Summer Afternoon Extreme Temperature Regression

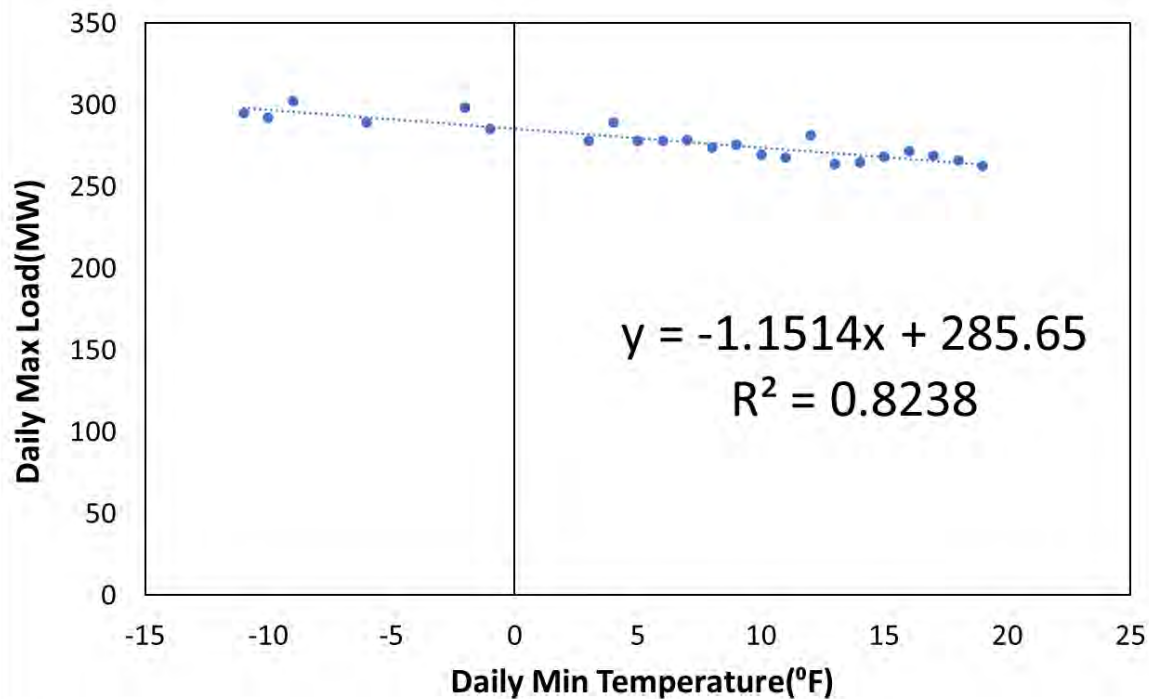


Figure 22. Tri-WYWNE Winter Afternoon Extreme Temperature Regression

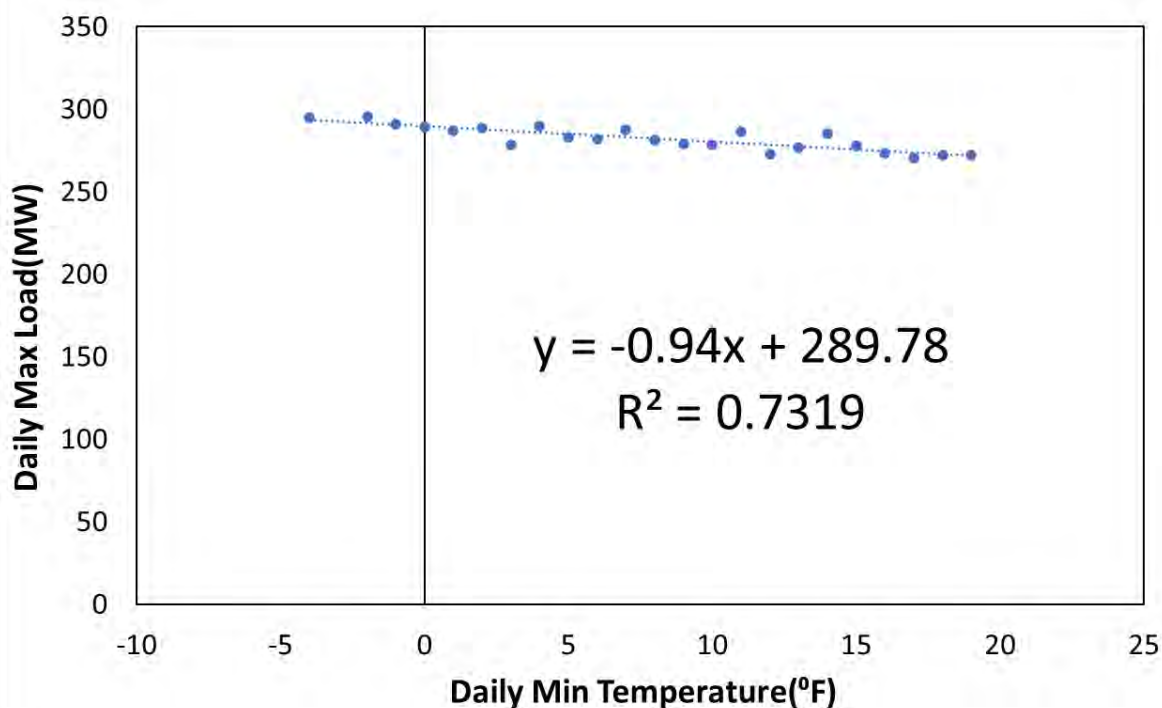


Figure 23. Tri-WYWNE Winter Morning Extreme Temperature Regression

The synthetic load shapes were then quality checked against the actual historical shapes to ensure their validity.

The figures below show a plot of the daily peak loads for each TSGT load region as a function of either the daily max or daily min temperature as appropriate. The figure compares the five years of historical data with the 42 years of synthetic data.

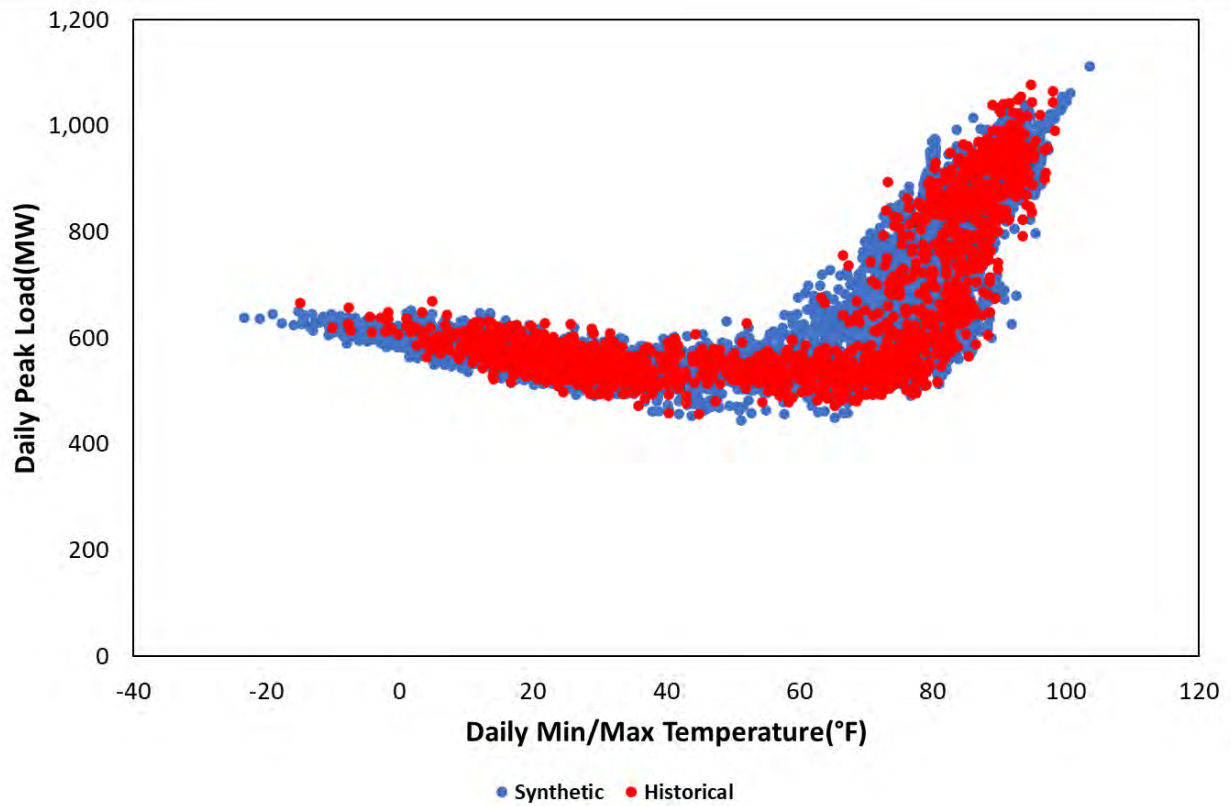


Figure 24. Tri-ECO Synthetic vs. Historical Daily Peak Loads

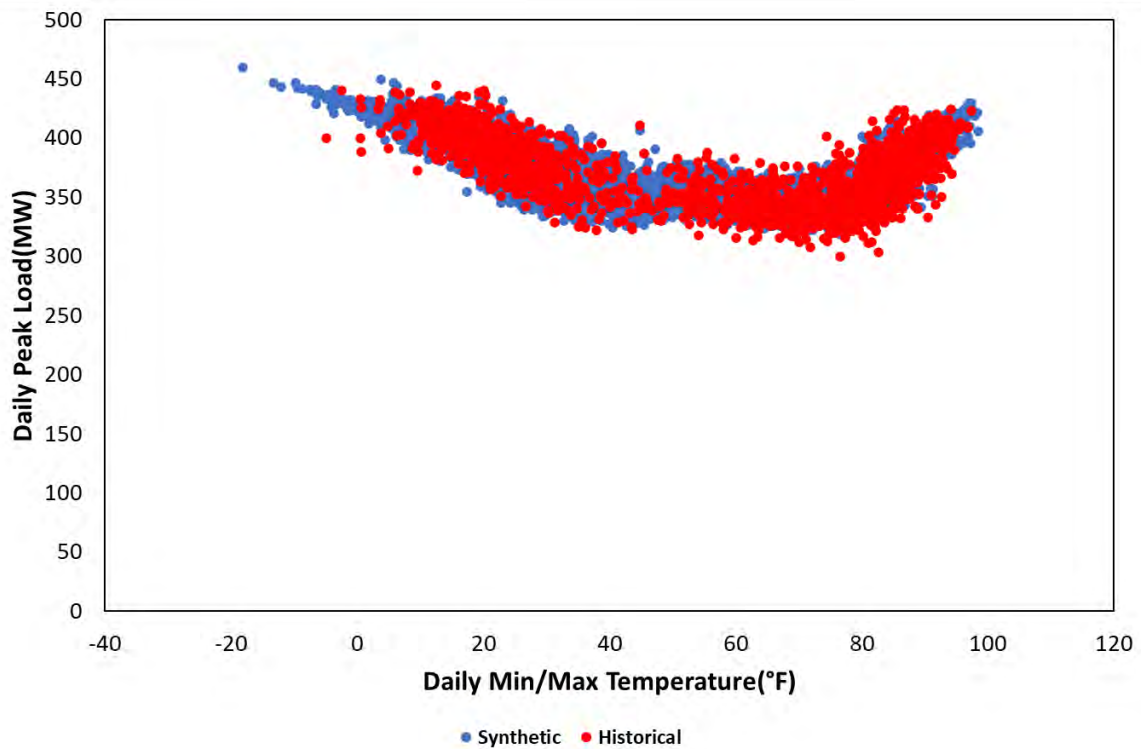


Figure 25. Tri-WCO Synthetic vs. Historical Daily Peak Loads

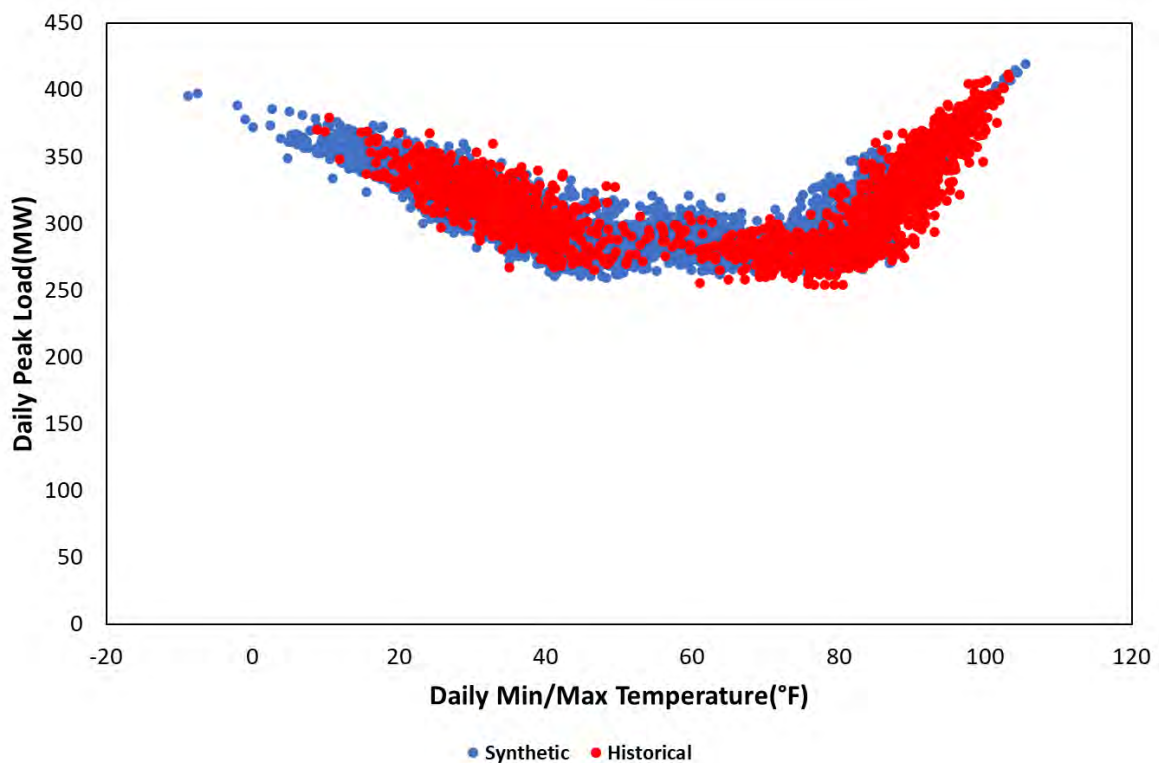


Figure 26. Tri-NM Synthetic vs. Historical Daily Peak Loads

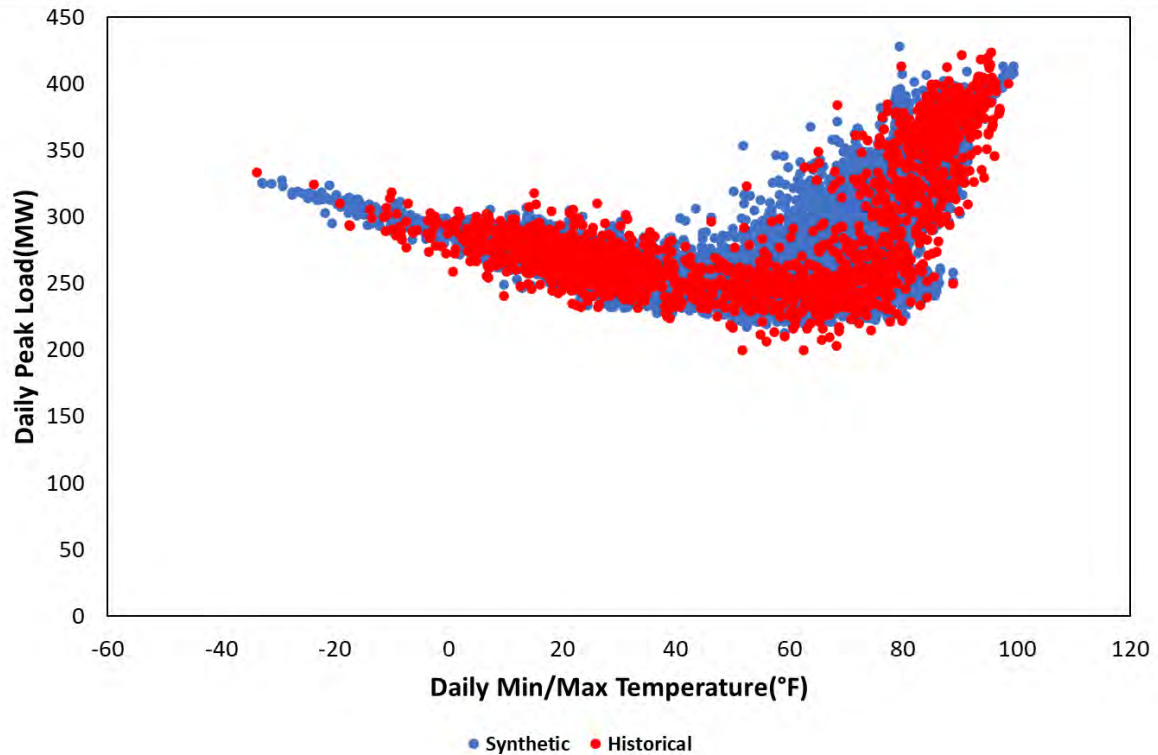


Figure 27. Tri-WYWNE Synthetic vs. Historical Daily Peak Loads

Focusing on the most extreme hours, the figures below show this same comparison for just those days in which temperatures were most extreme. The figure demonstrates a close correlation between the synthetic loads and the historical loads.

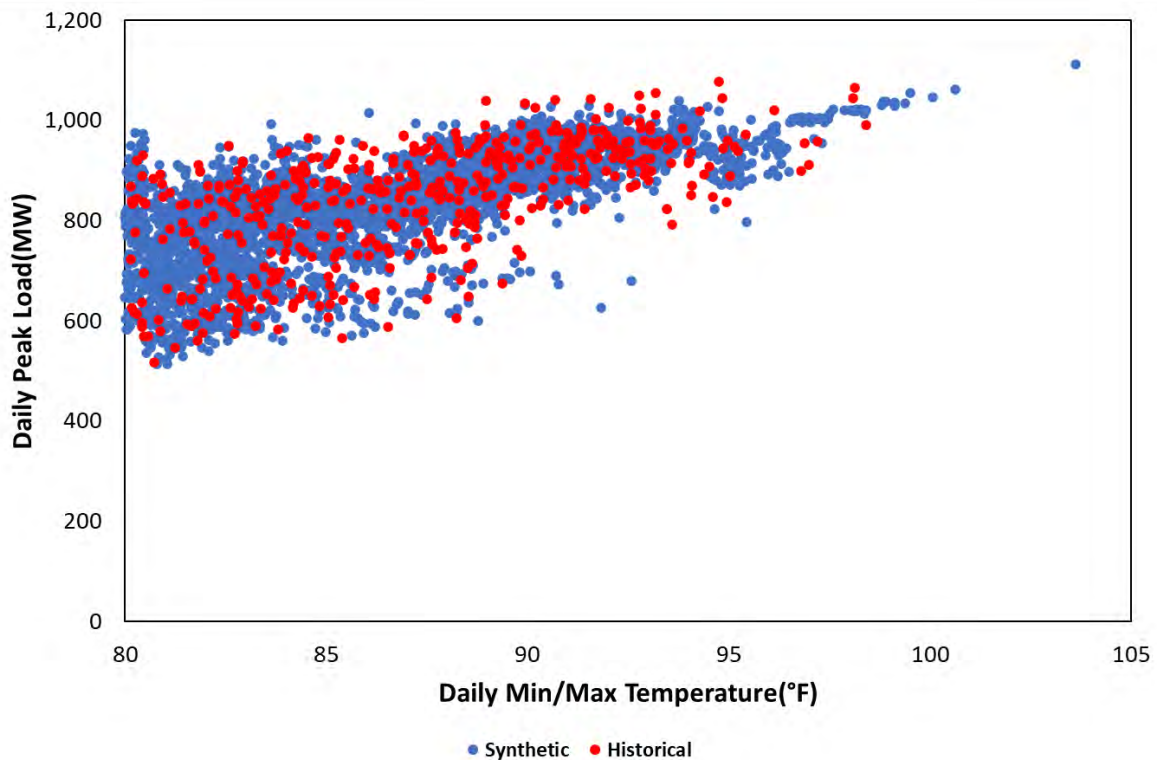


Figure 28. Tri-ECO Synthetic vs. Historical Loads for Extreme Temperatures

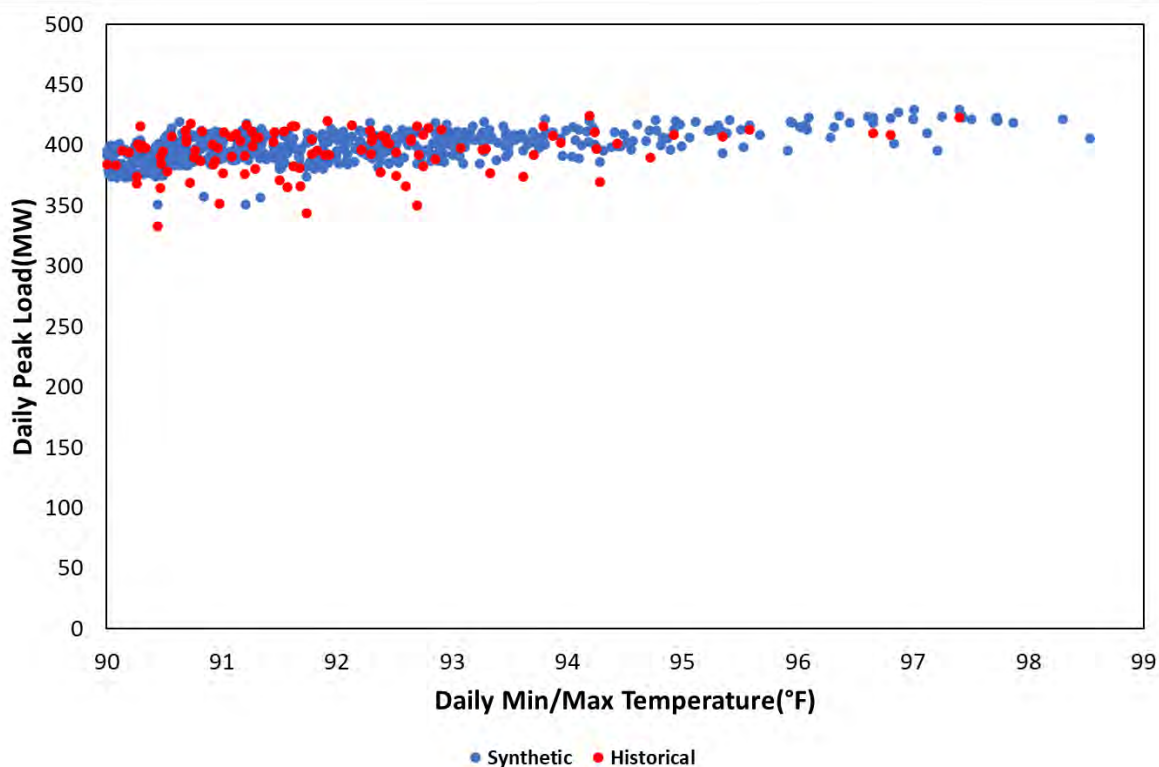


Figure 29. Tri-WCO Synthetic vs. Historical Loads for Extreme Temperatures

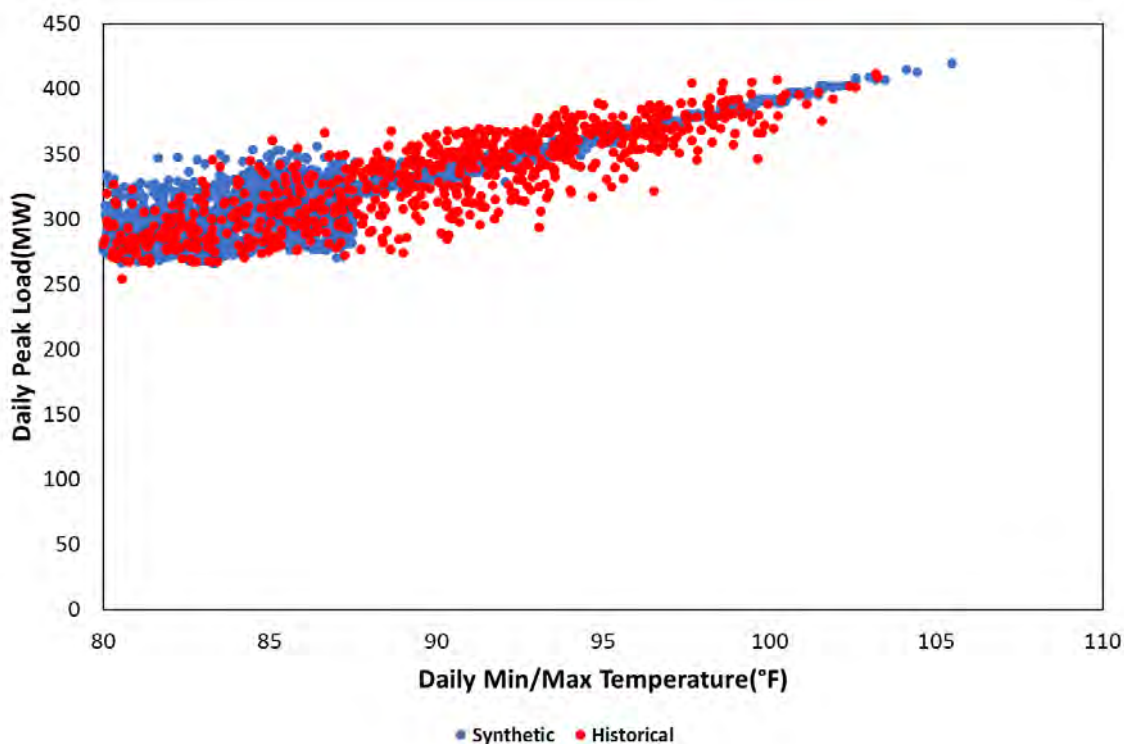


Figure 30. Tri-NM Synthetic vs. Historical Loads for Extreme Temperatures

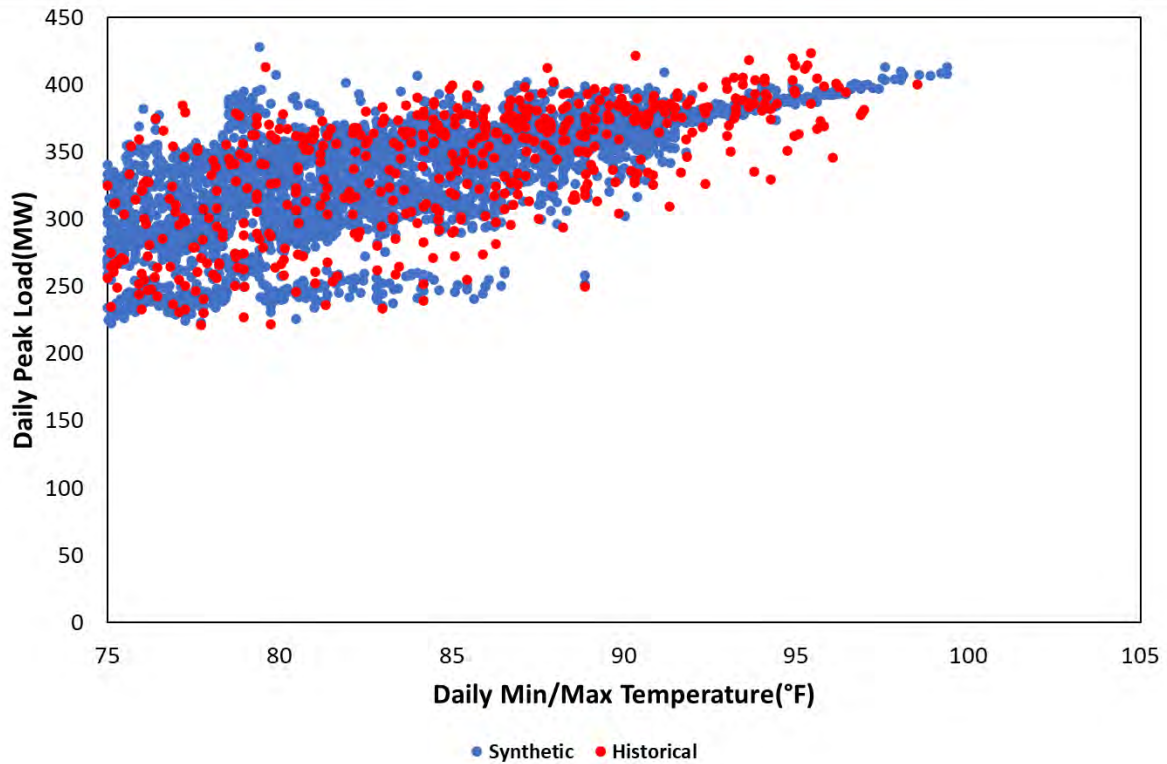


Figure 31. Tri-WYWNE Synthetic vs. Historical Loads for Extreme Temperatures

The development of the 42 synthetic load shapes results in a diverse set of annual peak loads. Within SERVIM, these shapes were scaled such that the median of the last 10 years of annual peak loads will equal the TSGT weather normal forecasted peak load. The figures below show the summer and winter peak load variance resulting from the 42 synthetic load shapes for each of the TSGT load zones. The variance is shown on a percentage basis in terms of its divergence from the 10-year median (a.k.a., weather normal load), sorted from lowest to highest.

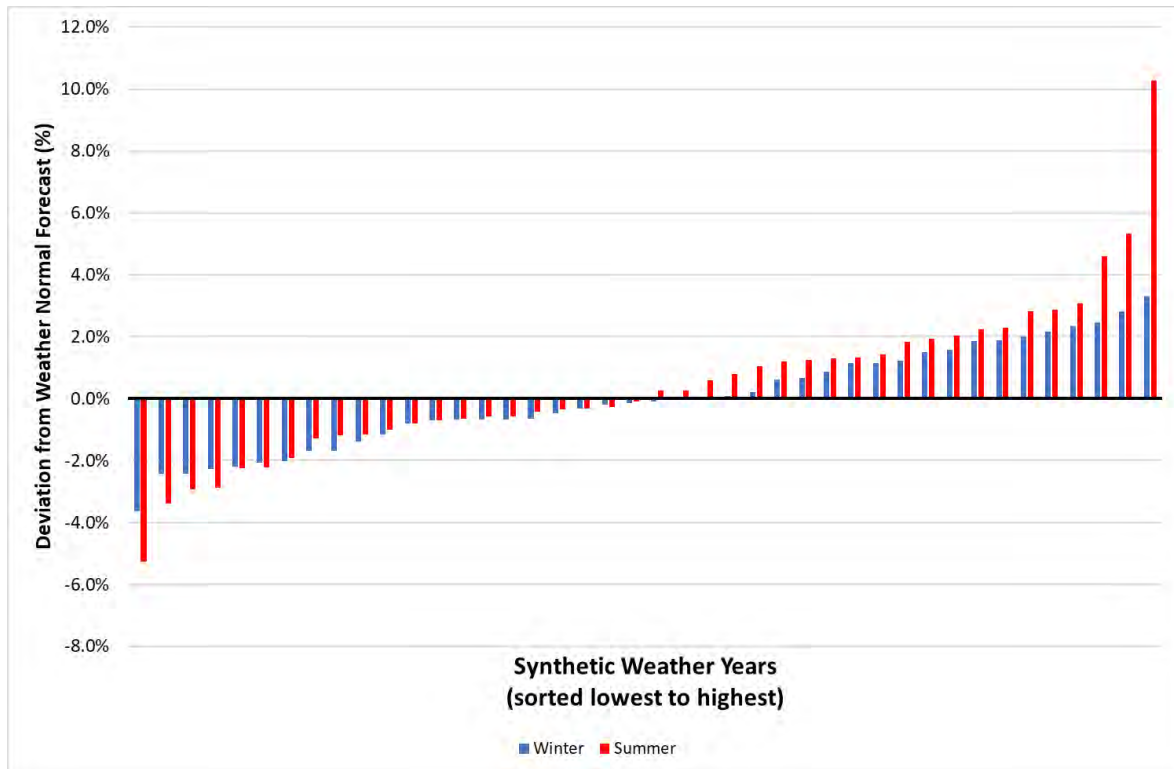


Figure 32. Tri-ECO Peak Load Variance

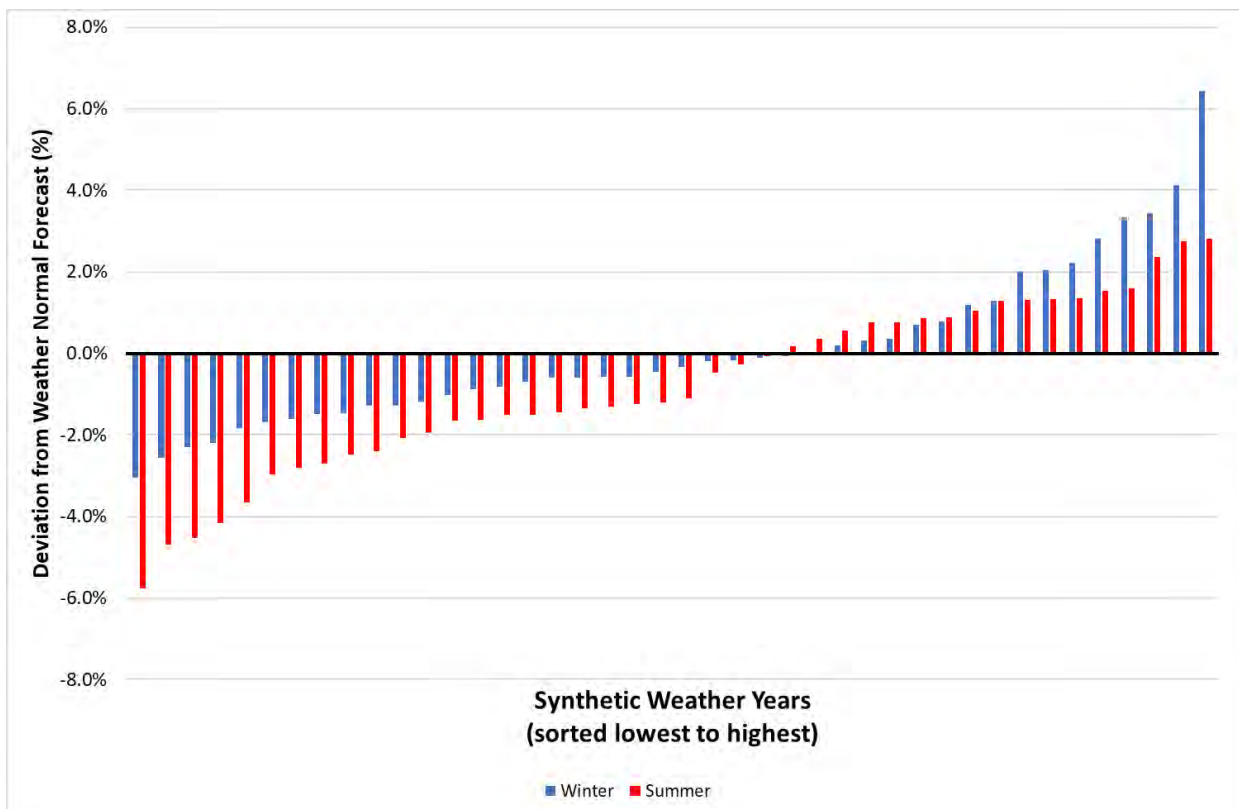


Figure 33. Tri-WCO Peak Load Variance

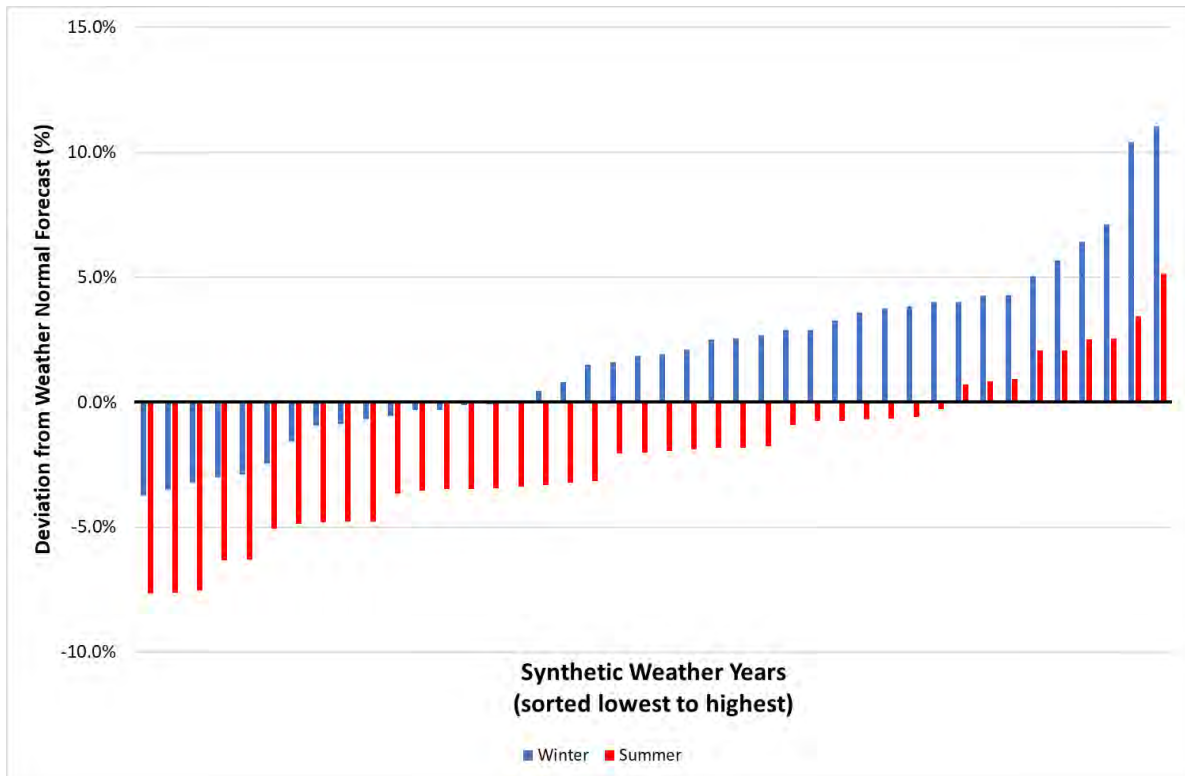


Figure 34. Tri-NM Peak Load Variance

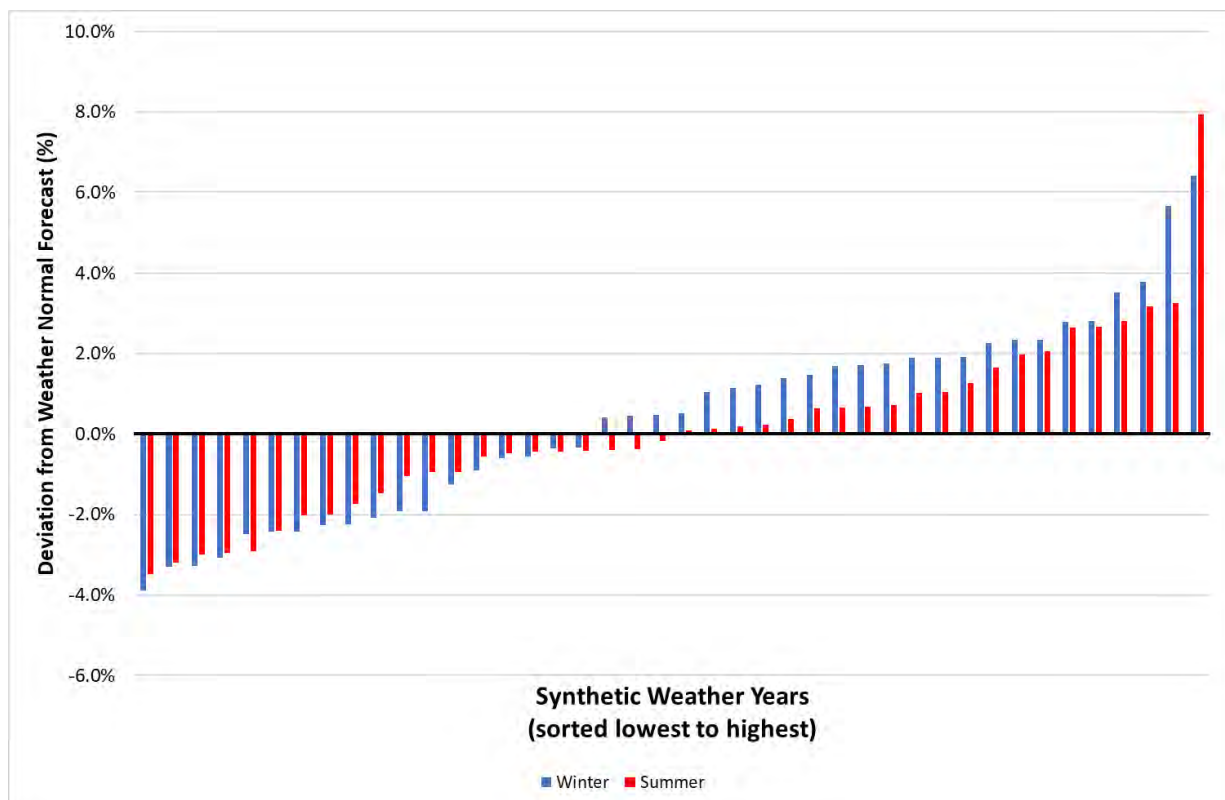


Figure 35. Tri-WYWNE Peak Load Variance

In addition to the raw loads, load modifiers were used to model incremental EE. The table below shows the 12x24 EE profile modeled for the EE programs in the Tri-ECO and Tri-WCO load zones. Values are shown in the percentage of maximum annual EE impact.

Table 3. TSGT EE Shape

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	53.8	48.3	45.7	30.8	39.9	40.1	38.7	41.2	40.0	35.3	28.0	31.3
2	52.3	44.9	43.7	29.6	38.8	39.2	37.8	39.2	38.0	33.5	25.2	29.0
3	51.3	44.2	42.3	30.2	39.6	39.5	38.2	38.9	38.7	32.9	24.4	27.9
4	52.1	44.1	43.3	32.7	41.6	40.4	40.8	39.7	41.5	33.6	25.9	29.9
5	53.8	47.2	47.3	36.2	44.8	42.8	43.6	42.3	45.0	38.2	29.2	33.0
6	57.2	51.0	51.9	40.2	49.9	47.5	48.1	45.5	47.6	42.8	33.4	37.3
7	61.6	55.1	55.3	43.9	53.6	52.1	53.3	49.0	51.3	47.3	37.8	42.2
8	64.8	58.3	59.5	46.5	57.9	58.2	59.8	52.6	53.8	51.3	42.5	46.4
9	67.7	62.5	63.4	49.0	59.2	63.2	66.5	55.3	58.1	54.0	45.7	50.2
10	69.4	66.3	65.1	50.5	62.3	67.4	70.7	60.0	64.4	56.1	47.5	51.9
11	70.3	67.1	68.1	50.8	63.9	72.4	74.2	61.0	68.2	58.8	48.1	53.0
12	70.4	67.4	68.5	52.3	64.8	75.9	75.0	60.9	71.6	60.8	49.0	53.6
13	70.2	67.4	69.2	53.1	68.6	78.1	75.7	61.1	76.0	61.3	49.4	54.0
14	70.9	67.3	69.9	54.0	70.1	79.0	77.6	63.8	77.5	63.3	50.2	53.5
15	70.9	67.0	70.6	54.8	72.2	80.5	80.4	66.7	78.4	64.5	50.7	54.2
16	71.9	68.1	71.1	55.3	73.4	80.5	81.3	70.5	80.5	65.7	51.7	55.6
17	73.3	69.6	72.6	57.4	73.9	81.5	81.5	72.4	79.3	66.4	52.8	56.6
18	76.8	71.1	74.1	58.2	72.4	80.0	81.4	72.7	76.2	65.4	54.5	58.0
19	78.0	72.4	75.7	57.0	68.5	77.0	77.6	69.2	72.6	64.1	55.1	58.7
20	77.8	72.9	74.6	54.7	63.6	69.7	72.7	65.8	67.1	61.5	53.6	57.4
21	74.7	70.8	71.1	49.9	58.5	63.1	65.6	60.1	60.2	56.1	50.1	53.9
22	69.6	66.7	65.6	44.5	51.4	55.3	57.3	53.4	52.5	49.9	44.9	48.3
23	64.1	59.8	58.6	38.1	45.9	48.0	48.3	47.5	46.1	43.7	38.5	41.8
24	58.2	52.4	50.6	33.2	39.6	41.8	42.4	41.7	40.9	38.8	32.8	35.7

The maximum annual EE impact for Tri-ECO in 2030 is 10.1 MW. The maximum annual EE impact for Tri-WCO in 2030 is 3.3 MW.

ECONOMIC FORECAST ERROR

As described in the Study Framework subsection of the Introduction section of this document, five LFE multipliers with their associated probabilities were applied to each of the 42 historical load shapes. The LFE multipliers simulate the expected probability that the peak demand forecast would be missed because of errors in the forecast of economic growth. The multipliers were developed by looking at the historical error in the 4-year out forecast GDP assuming a peak demand sensitivity to changes in GDP of 0.4% per 1% change in GDP. The set of LFE multipliers along with their probability of occurrence used in this study are shown in the table below with a graphic representation in the figure that follows.

Table 4. LFE Model

LFE	Probability
-4%	7.9%
-2%	24.0%
0%	36.2%
2%	24.0%
4%	7.9%

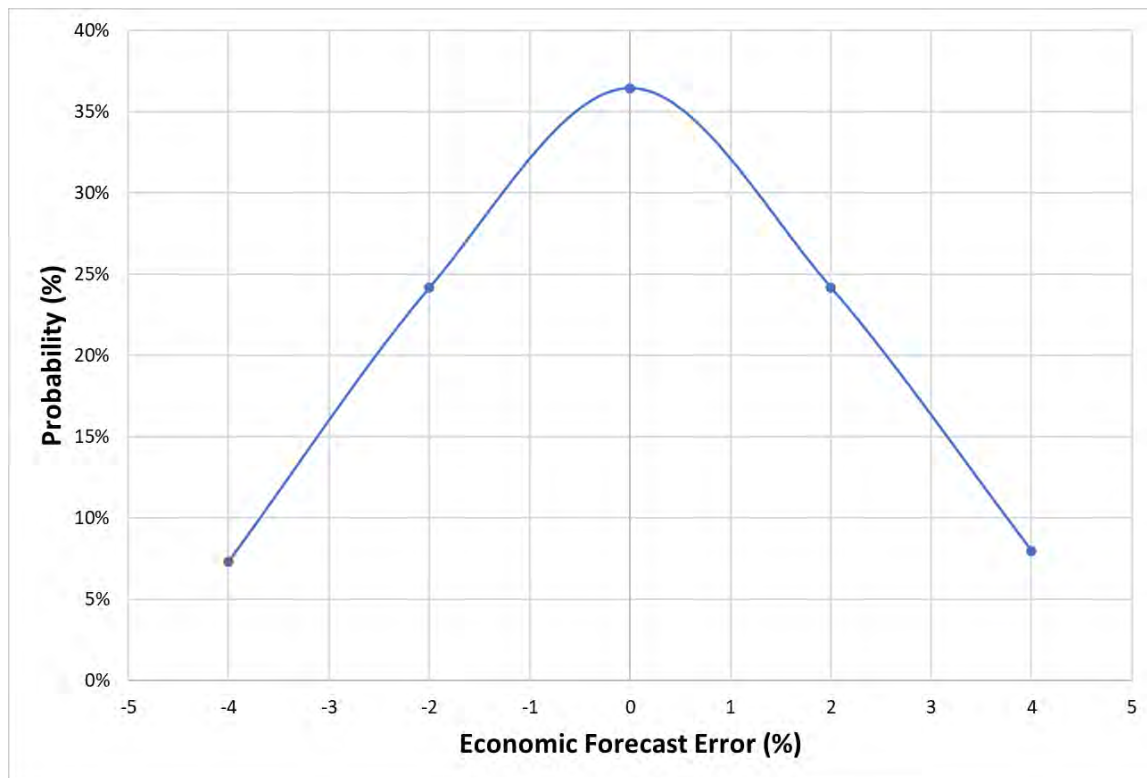


Figure 36. LFE Model

CONVENTIONAL RESOURCE MODELING

Resources for neighboring entities were developed using publicly available information. Resources for TSGT were developed using data provided by TSGT as outlined in the subsections below.

CONVENTIONAL GENERATING CAPACITY

The following table shows a summary of all the Conventional resources assumed to be available to TSGT in 2030, along with their corresponding summer capabilities. This list includes contract purchases and sales. Laramie River and Springerville are jointly owned coal units and the values shown represent the TSGT ownership share.

Table 5. TSGT Conventional Resource Capacities

Unit Name	Unit Category	Load Region	Capacity MW
Basin Ault	Contract Purchase	TRI_ECO	149.0
Basin Losses	Contract Purchase	TRI_WYWNE	8.0
Basin Stegal	Contract Purchase	TRI_WYWNE	119.0
Burlington 1	CT	TRI_ECO	48.0
Burlington 2	CT	TRI_ECO	48.0
Central Valley	Contract Purchase	TRI_NM	0.9

Knutson 1	CT	TRI_ECO	67.0
Knutson 2	CT	TRI_ECO	67.0
Laramie River 2	Coal	TRI_WYWNE	241.0
Laramie River 3	Coal	TRI_WYWNE	243.0
Limon 1	CT	TRI_ECO	67.0
Limon 2	CT	TRI_ECO	67.0
Native ECO	Contract Purchase	TRI_ECO	0.7
Native NM	Contract Purchase	TRI_NM	1.5
Native WCO	Contract Purchase	TRI_WCO	0.5
NWPP Purchase	Contract Purchase	TRI_WCO	0.9
NWPP Sale	Contract Sale	TRI_WCO	-0.4
Pyramid_1	CT	TRI_NM	40.0
Pyramid_2	CT	TRI_NM	40.0
Pyramid_3	CT	TRI_NM	40.0
Pyramid_4	CT	TRI_NM	40.0
Shafer	CC	TRI_ECO	272.0
Small Power Producer	Contract Purchase	TRI_WCO	0.2
Springerville3	Coal	TRI_NM	319.0
SMSG Purchase	Contract Purchase	TRI_NM	0.1
SMSG Sale	Contract Sale	TRI_NM	0.0

With the exception of the three Basin contract purchases, which were modeled based on hourly profiles provided by TSGT, the contract purchases and sales were modeled as fixed injections that varied monthly.

OUTAGE MODELING

Outage modeling consisted of two primary types of outages, planned maintenance outages (PO), and forced outages.

Planned Maintenance – SERVUM can model Pos as either discrete schedules or an annual rate calculated as the percentage of hours in the year. If modeled as a PO rate, SERVUM schedules planned maintenance in seasons where there would not typically be an expectation of reliability concerns. This determination is made by looking at all available weather year load shapes and developing a schedule that is least likely to cause reliability concerns. Maintenance rates were calculated using planned maintenance data provided by TSGT for the conventional resources.

Forced Outages – SERVUM models forced outages using multiple sets of time to fail (TTF) and time to repair (TTR) inputs for both full and partial outages. Each resource has its own set of TTF and TTR inputs that are used to establish that resource's EFOR. Using Monte-Carlo techniques, a TTF value is chosen randomly for each generating resource. That resource is then allowed to operate until it reaches the TTF threshold, at which point it is forced offline. Once it is forced offline, a TTR value is chosen randomly to determine how long the resource will be unavailable. That resource remains

offline until it reaches the TTR threshold, at which point it is once again made available and a new TTF variable is chosen for the resource. With sufficient Monte-Carlo iterations, the EFOR of the resource converges to its expected value.

TSGT provided historical Generating Availability Data System (GADS) data that was used to create an initial set of TTR and TTF values for each of the conventional resources. These TTR and TTF values were then tuned to targeted EFOR values provided by TSGT. The table below shows both the EFOR and the planned maintenance rates used for each conventional resource. All values are shown in percentages.

Table 6. Resource Outage Rates

Unit Name	EFOR	PO Rate
Burlington 1	30.0	0.8
Burlington 2	30.0	0.8
Knutson 1	7.3	5.3
Knutson 2	7.3	5.3
Laramie River 2	9.3	8.4
Laramie River 3	9.3	8.4
Limon 1	6.4	1.5
Limon 2	6.4	1.5
Pyramid_1	8.1	7.5
Pyramid_2	8.1	7.5
Pyramid_3	8.1	7.5
Pyramid_4	8.1	7.5
Shafer	7.6	3.6
Springerville 3	9.2	6.6

HEAT RATES

While heat rates do not have a direct impact on the reliability of the system, it is important to accurately represent the relative dispatch of resources on the system so that outages (which are affected by hours of operation and thus do affect reliability) can be accurately modeled. Heat input requirements are modeled within SERVVM using binomial (a.k.a., A-B-C) heat rate coefficients. Total heat input, average heat rates, and incremental heat rates, therefore, would be determined using the following formulas:

$$\text{Total Heat Input} = A + B \cdot X + C \cdot X^2$$

$$\text{Average Heat Rate} = A/X + B + C \cdot X \text{ and}$$

$$\text{Incremental Heat Rate} = B + 2 \cdot C \cdot X$$

Where X = the output of the resource in MW.

Heat rate coefficients for the conventional resources were provided by TSGT. The resulting average heat rate at maximum capacity is shown in the table below.

Table 7. TSGT Unit Heat Rates

Unit Name	Unit Category	Heat Rate (MMBtu/kWh)
Burlington 1	CT	14.0
Burlington 2	CT	14.0
Knutson 1	CT	11.6
Knutson 2	CT	11.6
Limon 1	CT	11.9
Limon 2	CT	11.9
Pyramid_1	CT	9.7
Pyramid_2	CT	9.7
Pyramid_3	CT	9.7
Pyramid_4	CT	9.7
Shafer	CC	9.3
Laramie River 2	Coal	10.0
Laramie River 3	Coal	10.4
Springerville 3	Coal	10.0

FUEL COSTS

As with heat rates, precise accuracy in fuel costs does not directly impact reliability. However, as with heat rates, the relative cost of one fuel source to another can affect unit operations, which in turn can affect unit outage modeling. Monthly fuel costs were provided by TSGT as shown in the figure below for the 2030 study year in 2030 dollars. Fuel prices for other regions and technologies were determined from publicly available sources.

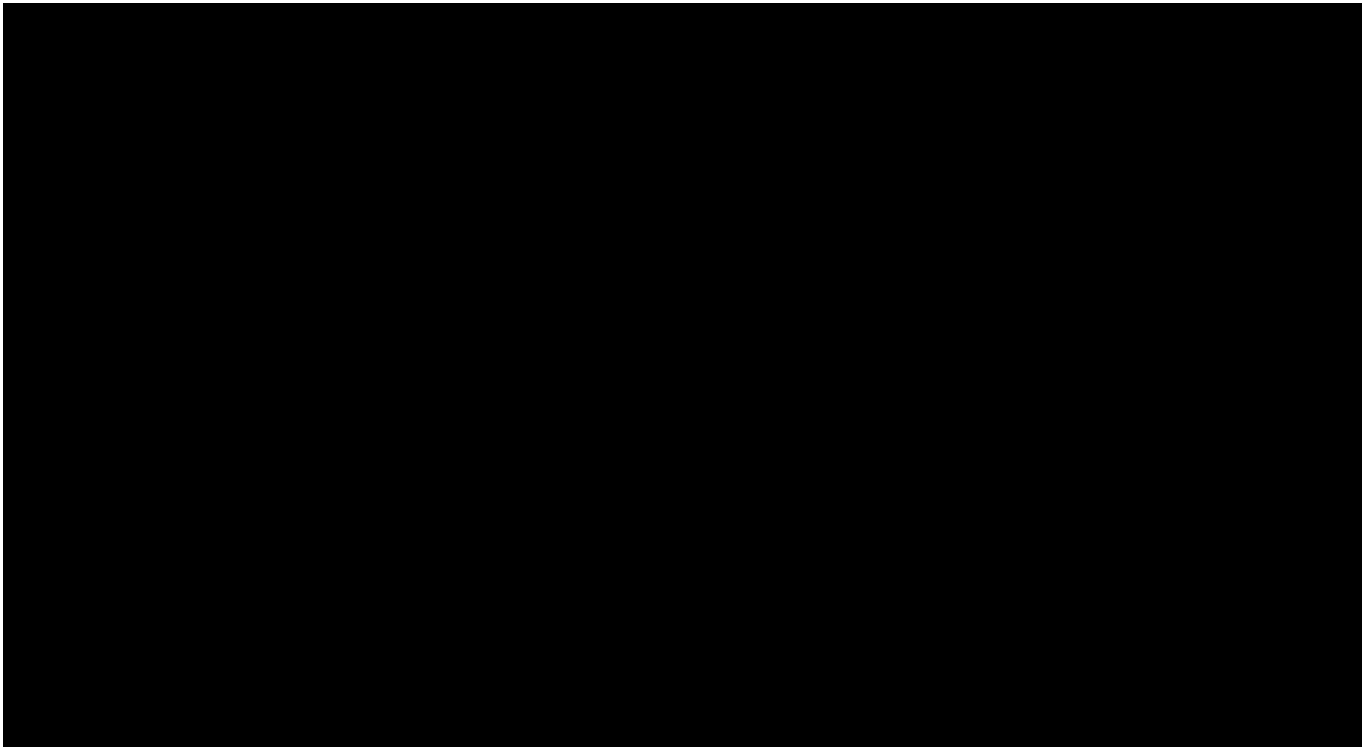


Figure 37. TSGT Monthly Fuel Costs

OTHER CONVENTIONAL DATA

Other conventional resources data provided by TSGT included startup profiles, variable operation and maintenance, minimum capacities, minimum uptime, minimum downtime, and ramp rates. These were modeled as part of the analysis but had no direct bearing on the determination of the reserve margin except to the extent they may have affected hours of operation and thus (ultimately) outage profiles.

CUSTOMER RESOURCE MODELING

The following table shows the distributed generation and partial requirements resources provided by the TSGT retail service provider customers. Except for the solar and wind resources, these were all modeled as fixed injections. The BTMPV represents customer rooftop solar, and values were estimated and assumed based on information provided by TSGT.

Table 8. Customer Provided Resources

Unit Name	Unit Category	Region	Capacity MW
BTMPV_ECO	BTMPV	TRI_ECO	89.4
BTMPV_NM	BTMPV	TRI_NM	36.9
BTMPV_WCO	BTMPV	TRI_WCO	40.9
BTMPV_WYWNE	BTMPV	TRI_WYWNE	35.8
DG_ECO	Distributed Gen	TRI_ECO	9.6
DG_Solar_ECO	Distributed Solar	TRI_ECO	185.6
DG_Solar_NM	Distributed Solar	TRI_NM	21.3

DG_Solar_WCO	Distributed Solar	TRI_WCO	24.7
DG_Solar_WYWNE	Distributed Solar	TRI_WYWNE	0.5
DG_WCO	Distributed Gen	TRI_WCO	10.3
DG_Wind_ECO	Distributed Wind	TRI_ECO	8.0
PR_NM	Distributed Gen	TRI_NM	30.0
PR_WCO	Distributed Gen	TRI_WCO	86.0
PR_WYWNE	Distributed Gen	TRI_WYWNE	47.0

See renewables sections below for details on how the solar and wind profiles were calculated.

SOLAR RESOURCE MODELING

In addition to the BTMPV and distributed solar brought by its retail service providers, TSGT has nine existing and/or planned solar facilities. The following table shows the list of modeled solar resources, with their locations mapped in the figure that follows the table.

Table 9. TSGT Solar Facilities

Unit Name	Capacity
Alta Luna	25
Axial	145
Cimarron	30
Coyote Gulch	140
Dolores Canyon	110
Escalante	200
San Isabel	30
Spanish Peaks 1	100
Spanish Peaks 2	40

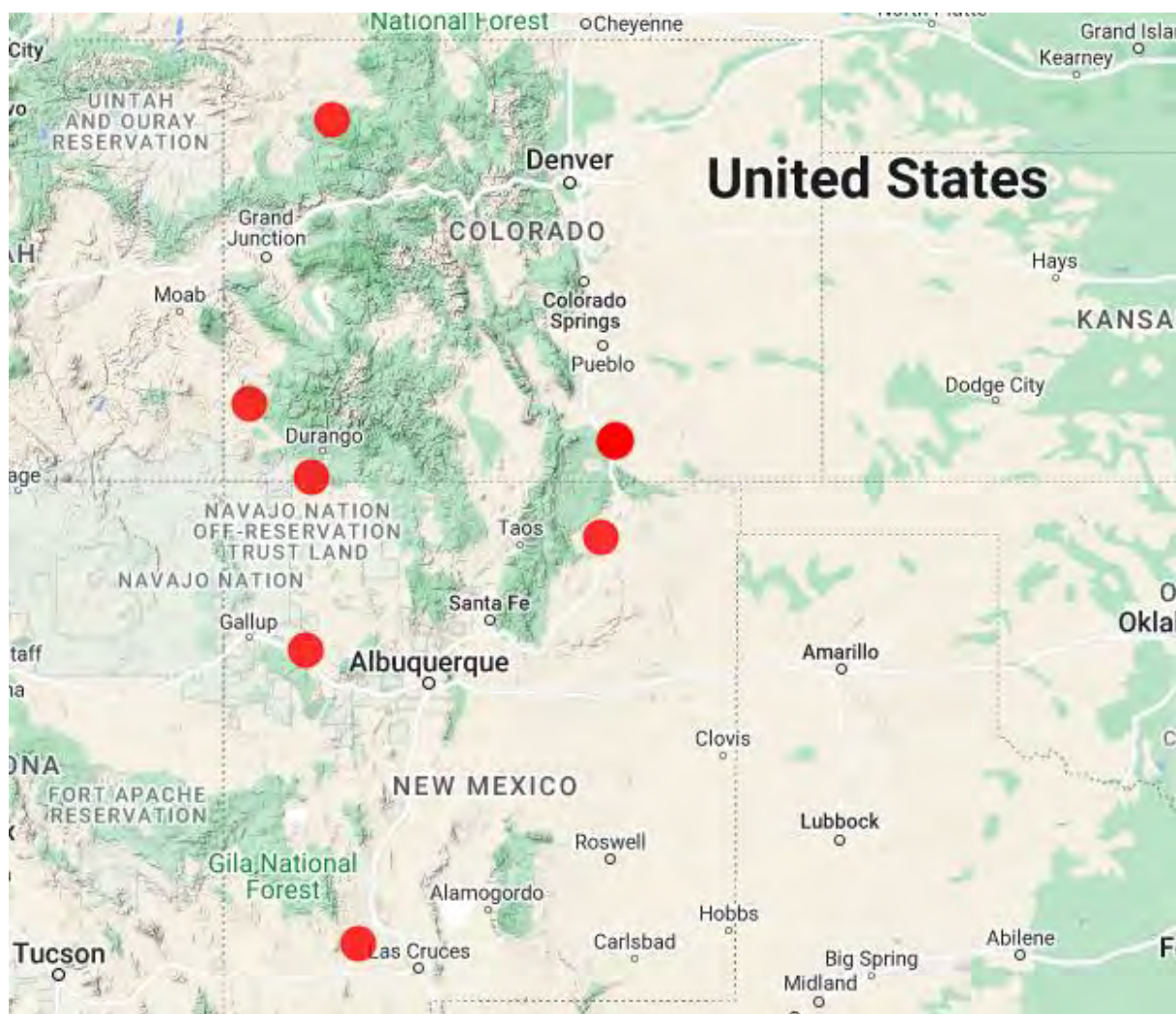


Figure 38. Location of TSGT Solar Resources

GPS coordinates for these locations can be found in the Appendix. Three of the resources, Spanish Peak 1 and 2 and San Isabel, are essentially co-located and were modeled as a single location.

SERVIM models renewable resources as an hourly profile for each weather year.

To create the weather year profiles, irradiance data for these seven locations were downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer for the years 1998 to 2020.³ The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar plants.⁴ Solar profiles for 1980 to 1997 and 2021 were selected by using the daily solar profiles from the day that most closely matched the peak load for the APS load out of all the days +/- 2 days of the source day for the 1998 to 2020 interval. The profiles for the remaining years 1998 to 2020 came directly from the solar shape output data from SAM.

³ <https://maps.nrel.gov/nsrdb-viewer/>

⁴ <https://sam.nrel.gov/>

For the BTMPV and Distributed solar facilities brought by the retail service providers, an aggregate profile was created by combining the profiles of all seven locations.

To ensure appropriate capacity and energy contributions, the resulting profiles were then adjusted using the inverter loading ratio (ILR) to achieve the desired capacity factor. The table below shows the list of solar sites with their historical capacity factor and the modeled ILR that achieves that capacity factor. For units with no historical data, the ILR and final capacity factor are assumed as shown to achieve an assumed 30% capacity factor.

Table 10. Solar Facility ILR and Historical Capacity Factors

Unit Name	Historical CF	ILR
Alta Luna	31.7%	1.075
Axial		1.24
Cimarron	23.5%	1.06
Coyote Gulch		1.07
Dolores Canyon		1.11
Escalante		1.03
San Isabel	28.6%	1.04
Spanish Peaks 1		1.1
Spanish Peaks 2		1.1

The figures below show respectively the resulting summer daily output profiles (average of June through September) for tracking, and fixed technologies for each of the seven sites modeled. The profiles assume an ILR of 1.0.⁵

⁵ i.e., the average of all July days including all weather years.

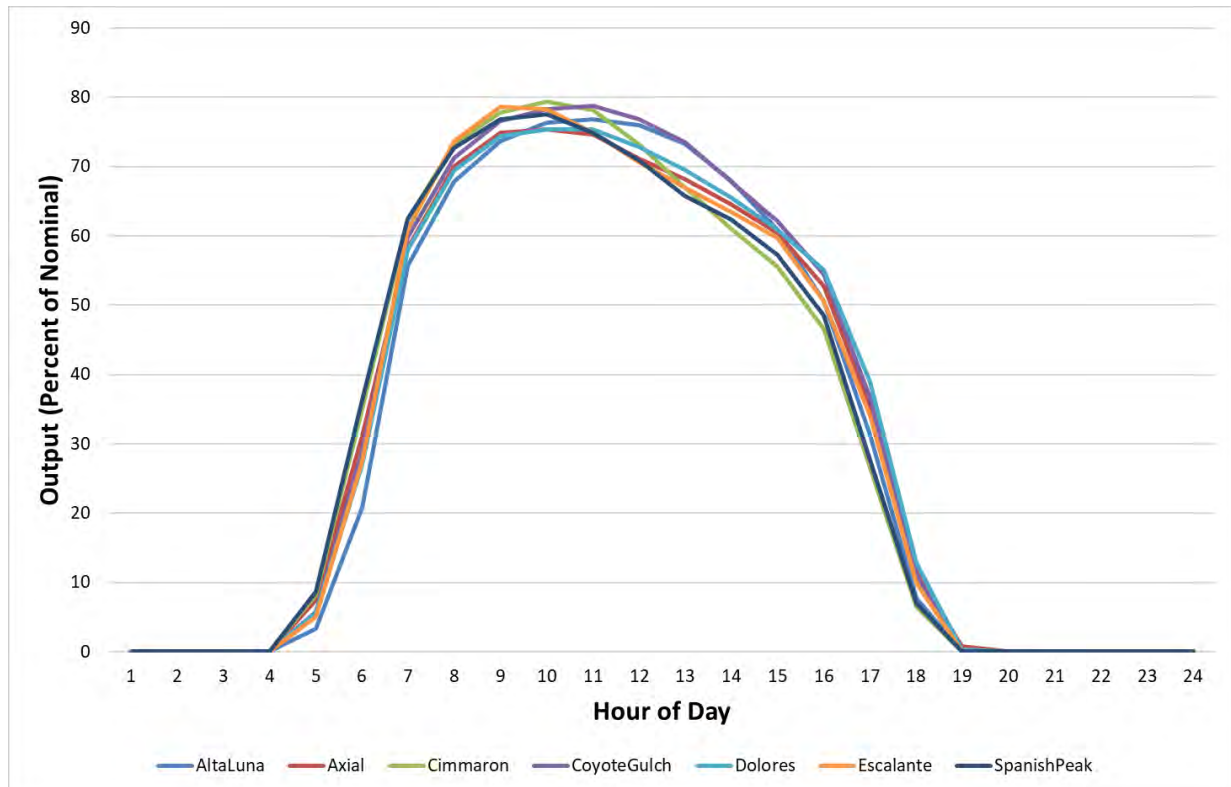


Figure 39. Average Summer Tracking Solar Profiles

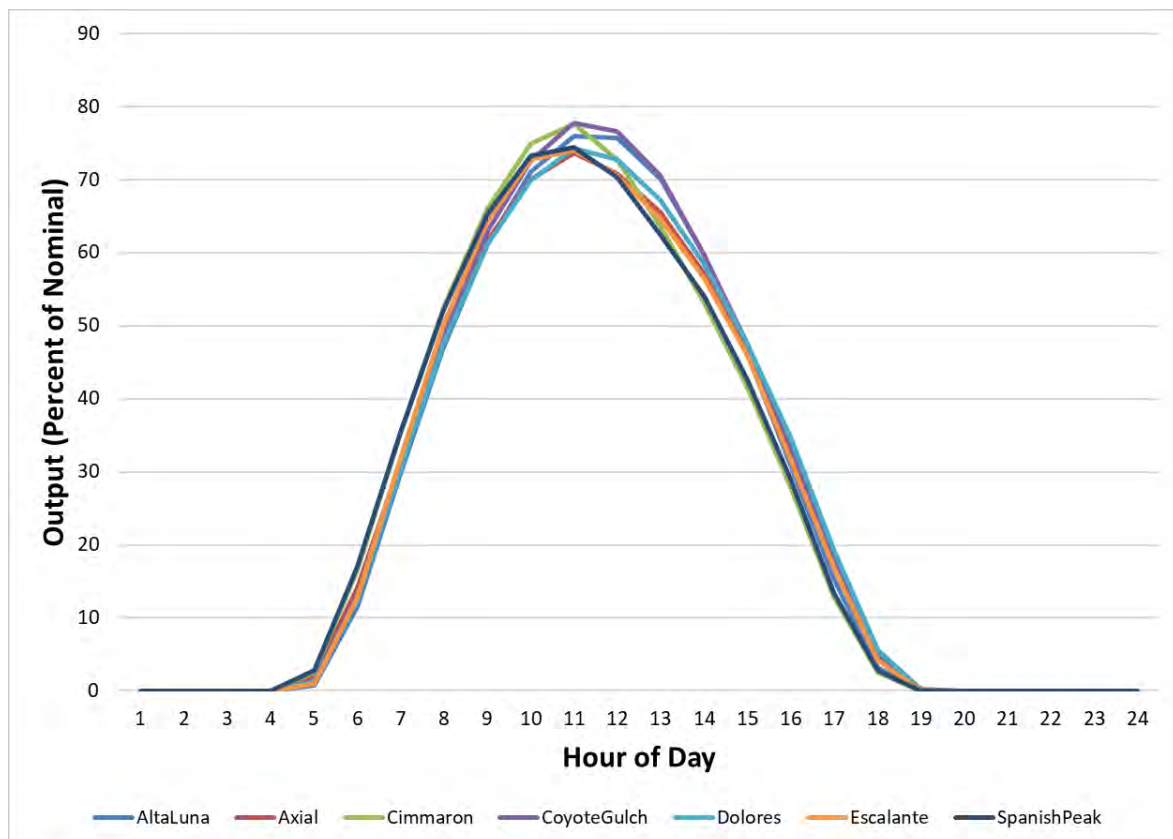


Figure 40. Average Summer Fixed Axis Solar Profiles

WIND RESOURCE MODELING

TSGT has six existing/planned wind resources as well as 200 MW of unspecified future wind capacity as indicated in the table below.

Table 11. TSGT Wind Resources

Unit Name	Capacity
Carousel	150
Colorado Highlands	94
Crossing Trails	104
Kit Carson	51
Niyol	200
Twin Buttes	75
Unspecified Wind	200

All of the existing wind is located in Colorado, while the new wind is anticipated to be in the Tri-WYWNE load zone (assumed for modeling purposes to be in Wyoming).

These projects were modeled assuming a single aggregate wind profile for Colorado and a single aggregate wind profile for Wyoming.

Synthetic wind profiles were developed using NREL's SAM tool for the years 2007-2014. Multiple coordinates were used per profile in each state and were combined to create an aggregate profile per state. NREL data, however, does not always accurately represent historical production data, especially during times of peak load output. Therefore, the NREL profiles were benchmarked using wind production data that was obtained from the EIA.gov website. For Colorado, wind data was downloaded and aggregated for the PSCO BAA. For Wyoming, wind data was downloaded and aggregated for the WACM BAA. The benchmarking process included two primary adjustments to the profiles. The first adjustment was to the overall shape of the profiles so that the aggregate load duration curves matched those of the downloaded production data. The second adjustment was to ensure that the output during peak load times was consistent with the historical data.

The following figures show the monthly output profiles in percent of nominal capacity for Colorado and Wyoming wind projects, respectively.

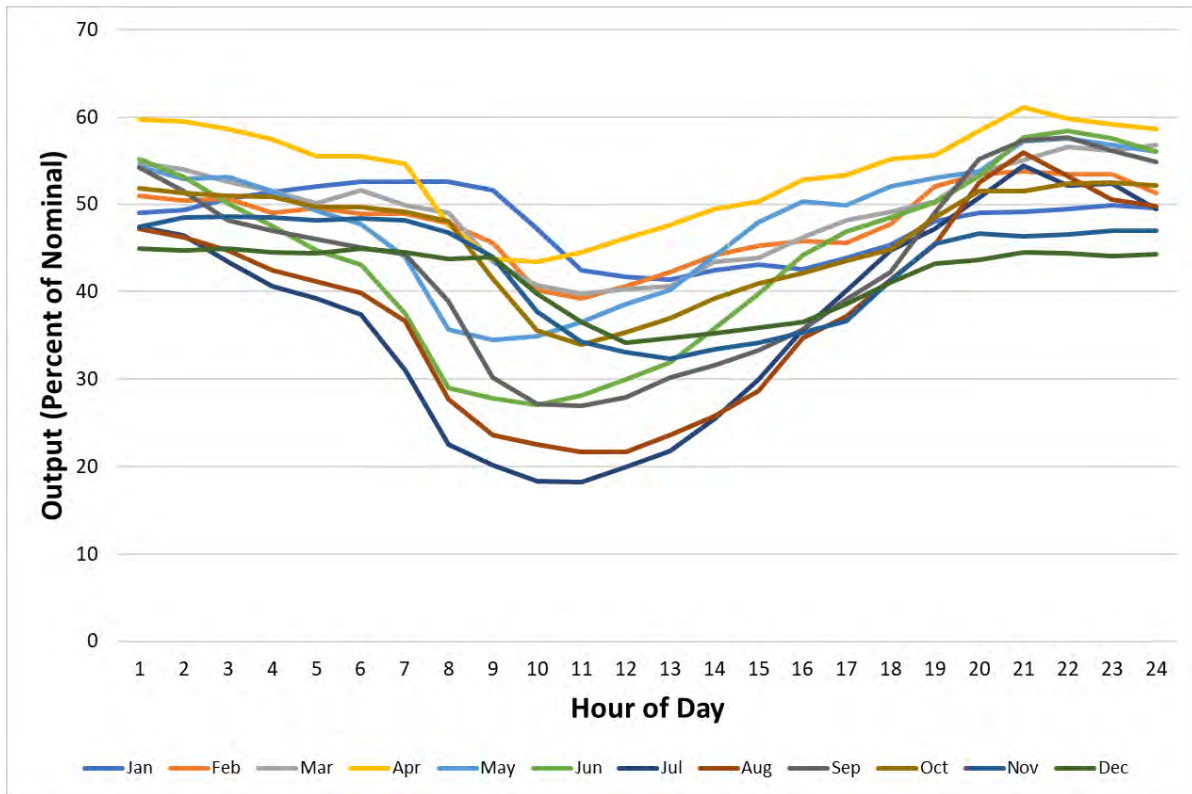


Figure 41. Colorado Wind Profiles

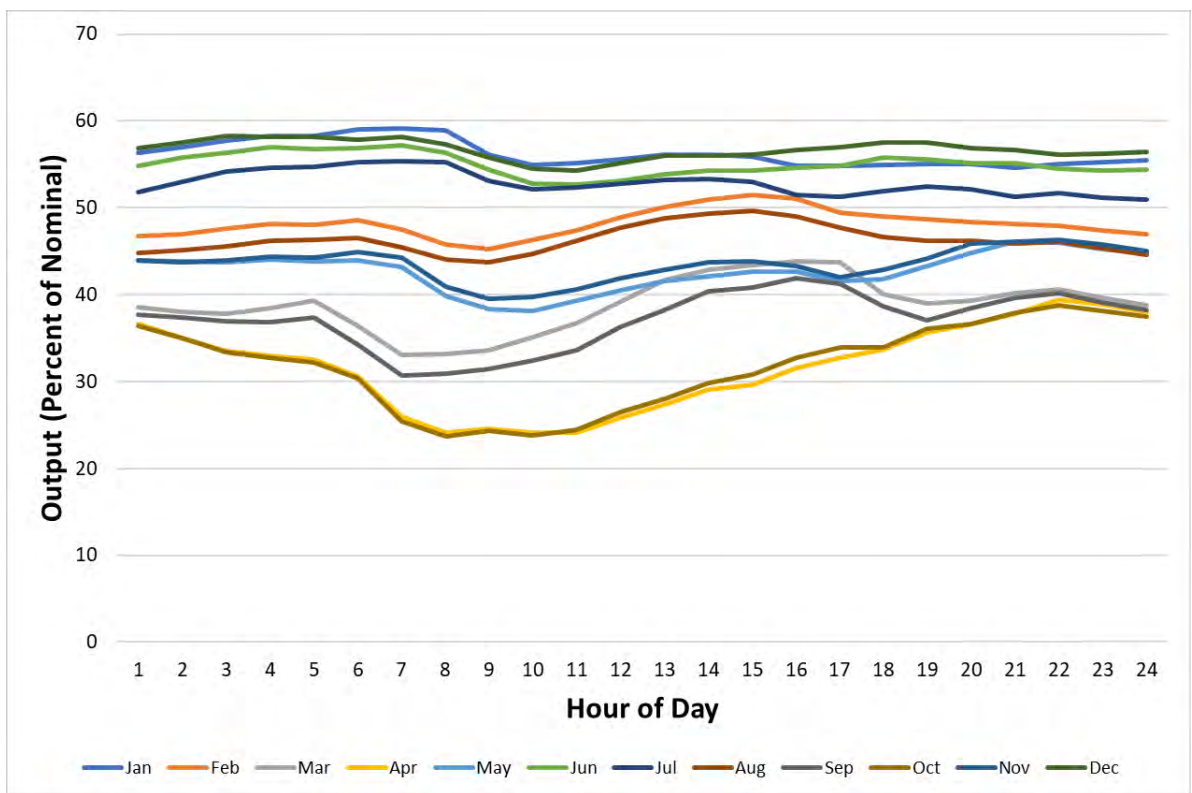


Figure 42. Wyoming Wind Profiles

As with the solar units, individual projects were further adjusted to match the project's historical capacity factor using the ILR. Future capacity was assumed to have a capacity factor of 45% and its ILR was set accordingly. The table below shows the capacity factors and associated ILRs for modeling purposes for each of the TSGT wind projects.

Table 12. TSGT Wind Historical Capacity Factors and ILRs

Unit Name	Historical CF	ILR
Carousel	47.8%	1.090
Colorado Highlands	44.2%	1.008
Crossing Trails	46.3%	1.055
Kit Carson	39.3%	0.895
Niyol	44.3%	1.010
Twin Buttes	47.4%	1.080
Unspecified Wind		1.000

STORAGE RESOURCE MODELING

TSGT does not have any battery storage facilities procured prior to 2030. Thus, no batteries are being modeled for them as part of the Base Case. However, battery storage will be a resource option in the 2023 ERP for the resource planning period and procurements will potentially occur in the resource acquisition period, 2026 to 2031. Thus, for ELCC modeling purposes, batteries were modeled with the following characteristics.

Table 13. Battery Storage Characteristics

Characteristic	Value
Storage Capacity (hours)	4
Charging Capacity (MW)	Same as Nameplate
Able to Provide Ancillary Services	Yes
Cycle Efficiency (%)	85

These battery storage resources were modeled as being available for economic arbitrage. However, during times of reliability risk, the economic arbitrage schedule was allowed to deviate so that the batteries would be discharged to avoid loss of load if storage capacity was available.

Based on recent industry experiences,⁶ grid-scale battery storage resources are expected to have outage rates of up to 15%, with improvements expected as operational experience improves. The long-term anticipated EFOR during hours of dispatch is expected to be in the 5% range. However, outages can occur in either charging or discharging periods, suggesting a 5% outage during both periods. For modeling purposes, therefore, to achieve a 5% overall EFOR in discharge hours, these (and all other) battery storage resources were modeled with a 10% forced outage rate applicable to both charging and discharging hours.

HYDRO RESOURCES

TSGT has one pumped storage hydro (PSH) facility and five hydro purchase contracts from WAPA. The hydro purchase contracts are scheduled on a two-day ahead basis with a contracted minimum and maximum hourly schedule amounts varying by month and monthly available energy amounts that change by month. The Mount Elbert PSH facility and the LAP_ECO WAPA contract share the same transmission export, which is limited to the WAPA contract value. Thus, it is not possible for both facilities to produce at their maximum value simultaneously. Therefore, the PSH facility can only produce energy to the extent the LAP_ECO WAPA contract is not fully scheduled. For this reason, no capacity accreditation is given to the Mount Elbert PSH facility in the PRM calculation. All modeled hydro facilities are shown in the table below.

Table 14. TSGT Hydro Facilities

Unit Name	Unit Category
CRSP_ECO	WAPA Purchase
CRSP_NM	WAPA Purchase
CRSP_WCO	WAPA Purchase
LAP_ECO	WAPA Purchase
LAP_WYWNE	WAPA Purchase
Mount Elbert	PSH

OTHER MODELING ISSUES

Due to time constraints and other factors, there were several items not specifically modeled for this evaluation that could have a minor impact on the resulting ICAP or UCAP PRM. Those items include demand response resources, incremental Beneficial Electrification (BE) load, and the Springerville

⁶ See <https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED>, slides 41-46, with emphasis on slide 46, "Specific lessons for battery storage".

hazard agreement that provides a 100 MW back up to Springerville 3 for up to 168 hours. It is anticipated that these and any other potential modeling enhancements will be incorporated in the next iteration of the reserve marginal analysis.

FINAL CAPACITY MIX

The figure below shows the final mix of capacity modeled for TSGT. It should be noted that BTMPV is not a resource available to TSGT and is excluded from their official load forecast. However, it is being modeled here as a resource with the forecast grossed up for the BTMPV.

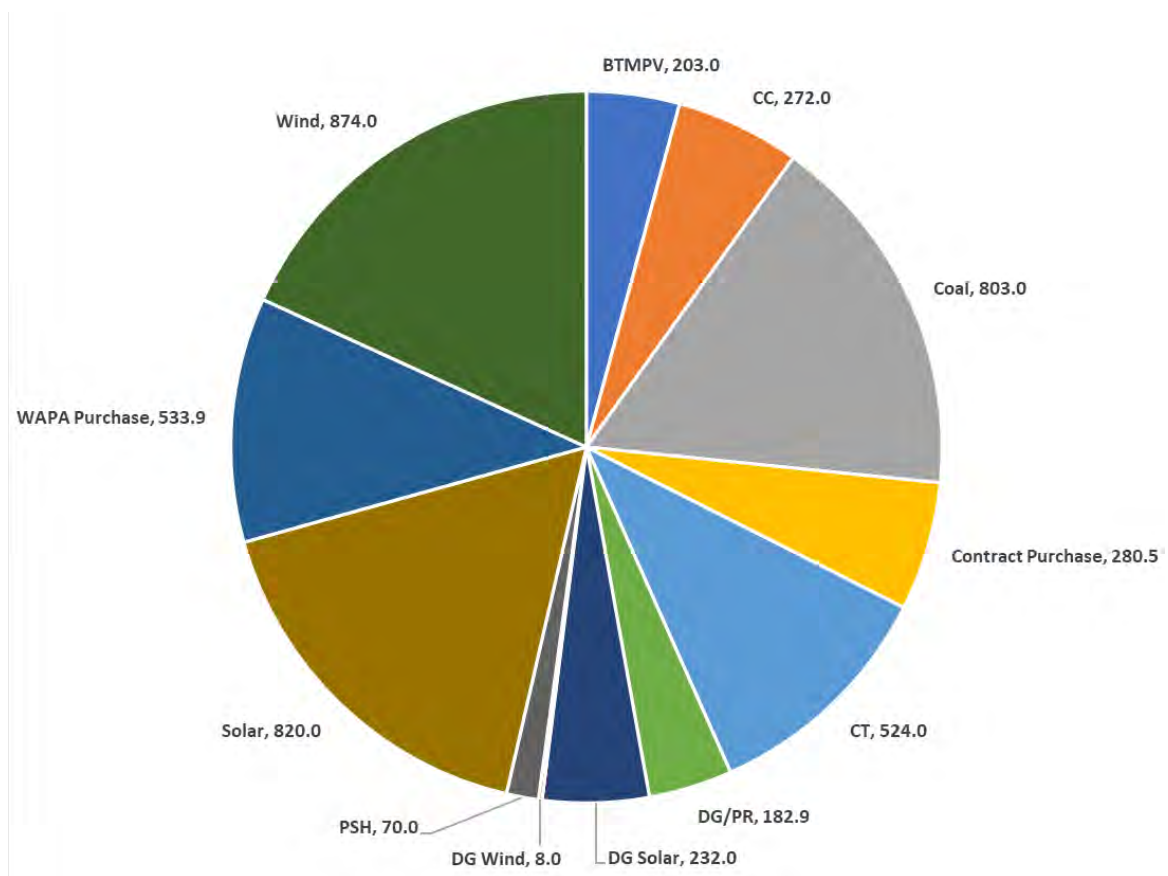


Figure 43. TSGT Capacity Mix (MW)

ANCILLARY SERVICES MODEL

Per information provided by TSGT, the ancillary services model included only 64 MW of Contingency Reserve-Non Spin in Colorado (split between Tri-WCO and TRI-ECO) and 67 MW of Contingency Reserve-Non Spin in Tri-WYWNE. In addition, 3% of load was included as a load following up target. Neither had a direct impact on the PRM because no reserves were maintained during load shed events.

STUDY APPROACH AND RESULTS

The two objectives of this study were to (a) establish the PRM for the TSGT system and (b) determine the ELCC for various penetrations of solar, wind, and BESS resources.

DEPENDABLE CAPACITY REQUIREMENTS

The PRM for the TSGT was determined for the 2030 study year. To determine the PRM, Combustion Turbine (CT) expansion capacity was added to TSGT until the system reached 0.1 days/year LOLE. This required making multiple runs with differing amounts of expansion CTs and then trending the resulting LOLE values so that the 0.1 LOLE point could be interpolated from the results. This established the total amount of dependable capacity required to maintain a reliable system. For TSGT, 59.2 MW of capacity was needed above their existing resource portfolio, to achieve 0.1 days/year LOLE.

PRM is an accounting exercise based on the amount of dependable capacity. To perform this accounting exercise requires the determination of the ELCC of the existing portfolio of renewable resources as described in the subsection below.

EXISTING PORTFOLIO ELCC AND RESULTING PRM

Determining the portfolio ELCC required the following steps:

1. Remove the full portfolio of solar and wind (including distributed solar and wind)
2. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE, and
3. Calculate portfolio ELCC by dividing the perfect added capacity by the nameplate capacity removed.

For the TSGT system, the total amount of renewable resources removed was 1,934 MW.⁷ The analysis described above resulted in a portfolio ELCC value of 350 MW or 18.0%.

Using the nameplate of the conventional resources plus the ELCC resources plus the expansion capacity, determination of the PRM (in %) is determined as follows:

$$\text{PRM} = [(\text{Conventional Capacity} + \text{ELCC Capacity} + \text{Adjustment Capacity}) / \text{Peak Load} - 1] * 100.$$

Those calculations are shown in the table below:

⁷ Because the resources are behind the meters for the load seen by TSGT or included in its load forecast, BTMPV was not included as part of the portfolio ELCC calculation.

Table 15. PRM Calculation

Component	Capacity	ELCC	Equivalent Capacity
Conventional Resources	2596.3		2596.3
ELCC Resources	1934.0	18%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			3003.6
Coincident Peak Load			2210.9
Reserves			792.8
ICAP PRM			35.9%

This PRM was developed using a coincident peak load that was developed as follows:

$$\text{CPL} = \text{Load}^8 - \text{EE}.$$

This PRM represents a significant increase in PRM over TSGT's current PRM requirement of 15%. One reason for the difference is in accounting. In the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Beyond the accounting, however, the key drivers in this PRM include the high EFOR of the conventional coal and CC resources as well as significant shaft risk due to the size of these units relative to the TSGT peak load. To demonstrate this impact, two additional analyses were performed. First, the ELCC of the CC and coal units were calculated. Then, a calculation was performed to demonstrate the impact on PRM if these units were smaller (aka no shaft risk) and had a considerably lower EFOR.

The table below shows the ELCC of the coal and CC units.

Table 16. Coal and CC ELCC

Resource	EFOR	ELCC
Shafer CC	7.8%	64.4%
Springerville Coal	9.2%	63.8%
Laramie River Coal	9.3%	58.8%

⁸ For purposes of PRM calculation, load was reduced for customer BTMPV consistent with TSGT's forecasting process.

These are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

Table 17. Impact of High EFOR and Shaft Risk

Component	ELCC	MW	Impact
CC	64.4%	272	175.168
SPV	63.8%	319	203.522
LRS	58.8%	484	284.592
Weighted	61.7%	1075	663.282
Target ELCC	90.0%	1075	967.5
Impact MW			304.2
Base Case Reliable MW			3003.6
Adj for EFOR/Shaft Impact			2699.4
Coincident Peak Load			2210.9
PRM			22.1%

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

To demonstrate the relationship between reserve margin and LOLE visually, the figure below shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE falling at a reserve margin of ~35.9%.

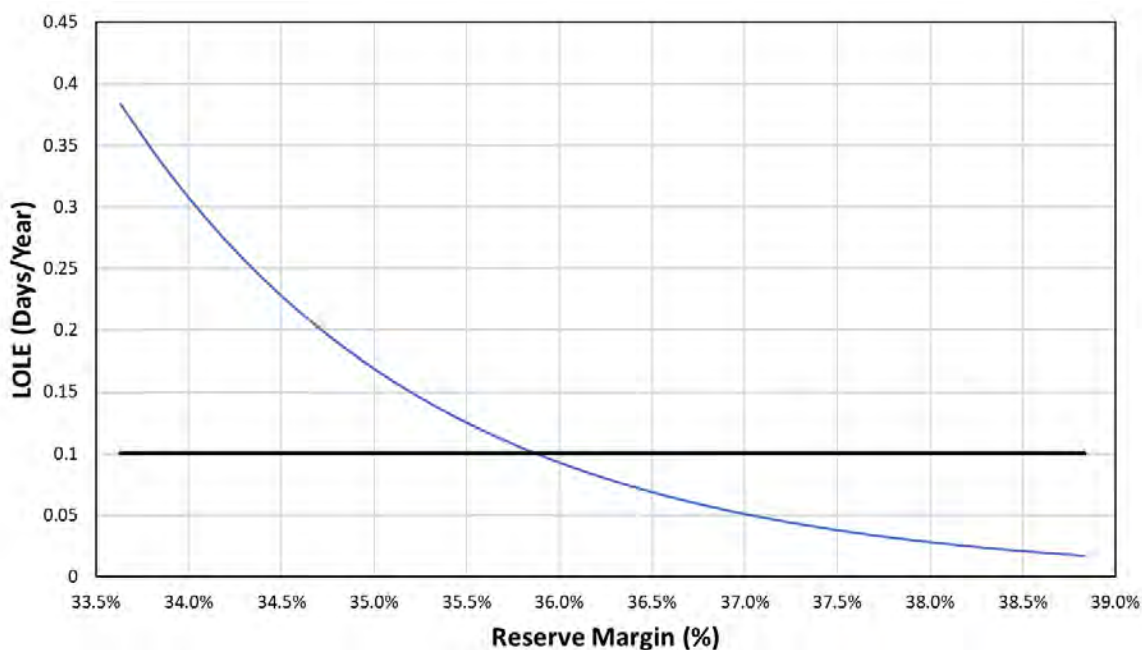


Figure 44. LOLE Analysis

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system EFOR resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. Given the current environment of increasing penetrations of renewable resources, that means PRM is expected to change over time.

An alternative accounting approach that attempts to stabilize the PRM by removing the effects of average forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by 1-EFORd for the conventional resources. The table below shows the UCAP Capacity for the TSGT conventional resources.

Table 18. TSGT UCAP Capacity

Unit Category	Nameplate MW	1-EFORd	UCAP MW
CT	524.0	96.9%	507.5
CC	272.0	93.7%	254.8
Coal	803.0	89.4%	717.8
UCAP Resources	1599.0	92.6%	1480.1

The table below shows the base case PRM assuming UCAP accounting using the UCAP capacity from above.

Table 19. Base Case UCAP PRM Accounting

Component	Capacity	UCAP/ ELCC	Equivalent Capacity
Firm Resources			997.3
UCAP Resources	1599.0	92.6%	1480.1
ELCC Resources	1934.0	18.0%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			2884.6
Coincident Peak Load			2210.9
Reserves			673.8
ICAP PRM			30.5%

However, EFOR (and EFORD) is based upon the average outage rate of the resource fleet. There are times when actual outages are higher than average and other times when they are lower than average. This creates an asymmetry in the outage profile, resulting in a true contribution to reliability that is less than the UCAP capacity. As such, UCAP accounting still results in a PRM that can change with significant changes to the system mix and penetration of renewable resources.

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and represent the same portfolio. The only difference is in the PRM accounting.

Because of this significant shaft risk, LOLE is being driven by outages as much as weather or load. As such, LOLE is expected across all weather years as demonstrated in the figure below.

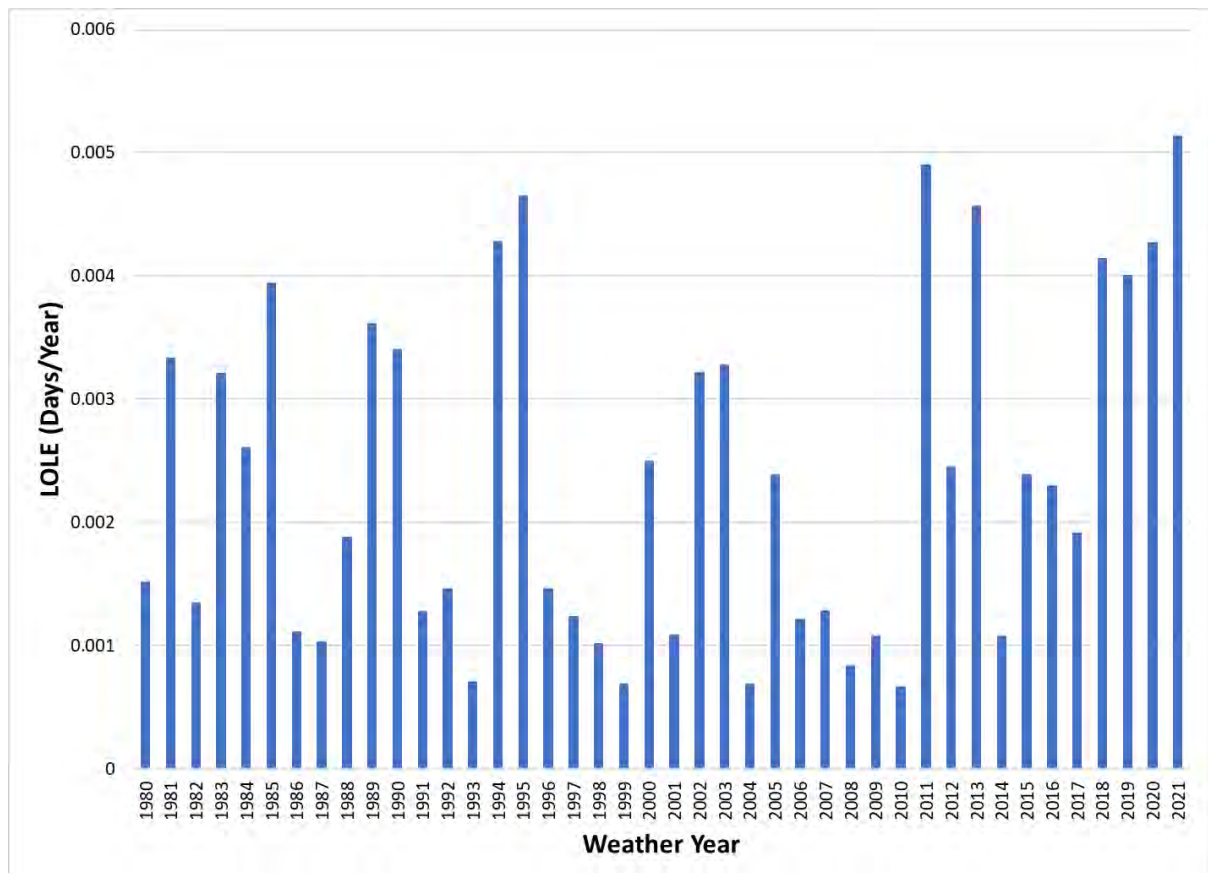


Figure 45. LOLE by Weather Year at PRM

To demonstrate the risk of loss of load by season, the figure below shows the breakdown of loss of load expectation by month. As the figure shows, the majority of the reliability risk for TSGT occurs in the summer months, although there is some risk in all months due to the shaft risk exposure associated with forced outages.

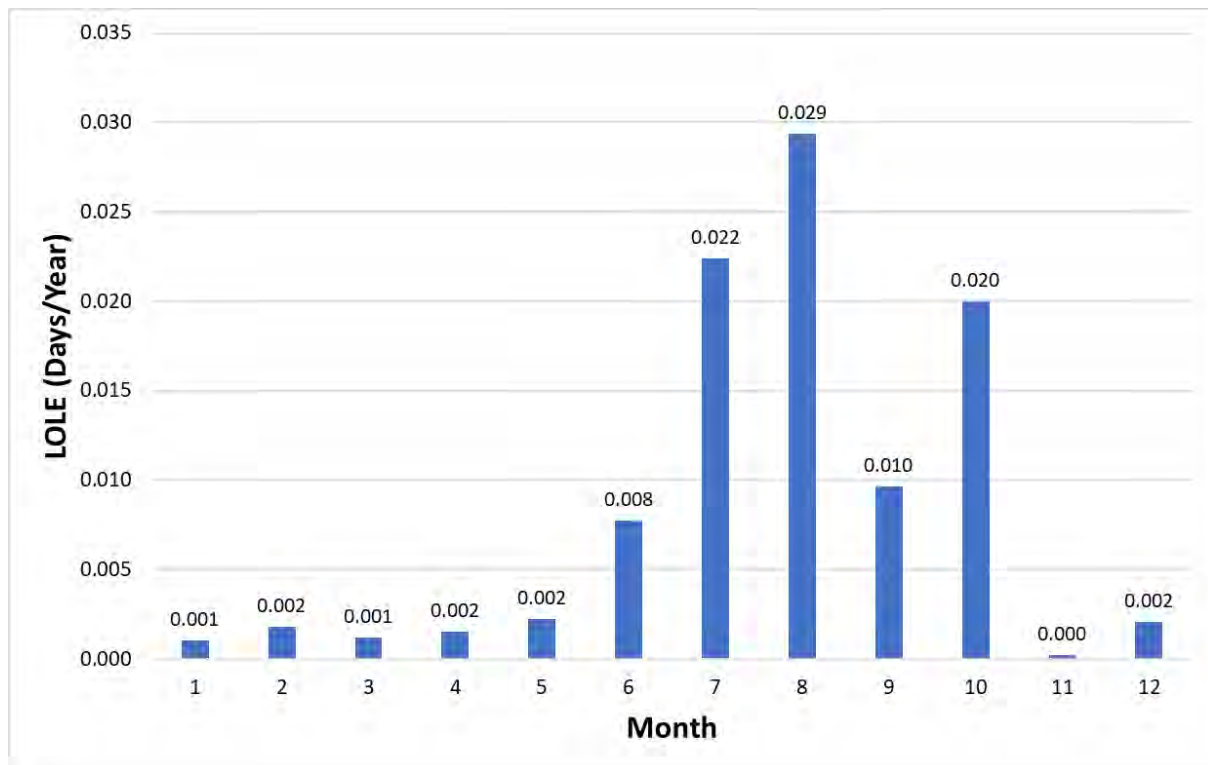


Figure 46. LOLE by Month at PRM

PRM RECOMMENDATION

Based on this analysis and based on TSGT's decision to use UCAP accounting for PRM purposes, a UCAP PRM of 30.5% is recommended. However, given the transitional period prior to 2030 in which departing member load has not yet left the system and coal units have not yet retired, a transitional PRM consistent with the shaft-risk and EFOR adjusted ICAP PRM of 22% can be supported.

TECHNOLOGY SPECIFIC ELCC

In addition to the base case portfolio ELCCs needed for the PRM calculation, analyses were performed to calculate average and marginal ELCCs by technology for solar, storage, and wind up to the following penetrations:

- Solar – 2,000 MW
- 4-hour Battery – 1,000 MW
- Wind – 2,000 MW

These ELCCs were first calculated within SERVIM for a subset of penetrations according to the following matrix. SERVIM runs were made for solar and battery combinations represented by the X marks for wind penetrations of 0 MW, 500 MW, 1,000 MW, 1,500 MW and 2,000 MW. The blue X mark was not run for the 0 MW wind penetration. The green X marks were only run for the 0 MW wind penetration.

Table 20. Matrix of SERVVM ELCC Runs

		Battery Storage (MW)					
		0	100	250	500	750	1000
Solar (MW)	0	X	X	X	X	X	X
	250	X					
	500	X					
	750	X					
	1000	X			X		X
	1250	X					
	1500	X					
	1750	X					
	2000	X			X		X

For purpose of developing this matrix, the BTMPV, customer distributed solar, and customer distributed wind were all considered pre-existing (i.e., underlying the test system), such that these penetrations would be considered incremental to those underlying penetrations of solar and wind.

Using pyramid smoothing techniques, this series of matrices were then expanded into a large three-dimensional dense matrix containing total portfolio values for any combination of solar, wind, and battery penetrations up to the specified maximum penetrations.

In addition to these solar, battery, and wind scenarios, additional scenarios were evaluated to determine the ELCCs for each of the following:

1. Customer Distributed DG,
2. Energy Efficiency, and
3. 10-hour Batteries.

ELCC METHODOLOGY

To determine the average ELCC for each of these scenarios, each scenario was evaluated in accordance with the following steps.

1. Develop a reference case for the scenario set (e.g., all the matrix solar/battery/wind scenarios used the same reference case)

- a. Remove the technology class(es) being evaluated (e.g., remove all existing solar, battery, and wind resources).
 - b. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE.
2. For each scenario, add back the penetration of the technology class(es) being evaluated (e.g., for the 500 MW solar scenario, add back 500 MW of solar).
3. Iteratively remove perfect capacity until the system returns to 0.1 days/year LOLE.
4. Divide the total amount of capacity added by the amount of perfect capacity removed to get the average ELCC for the scenario.

ELCC RESULTS

The result of this pyramid smoothing associated with the sparse matrix of SERVIM ELCC values was a dense three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the range of penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any desired penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

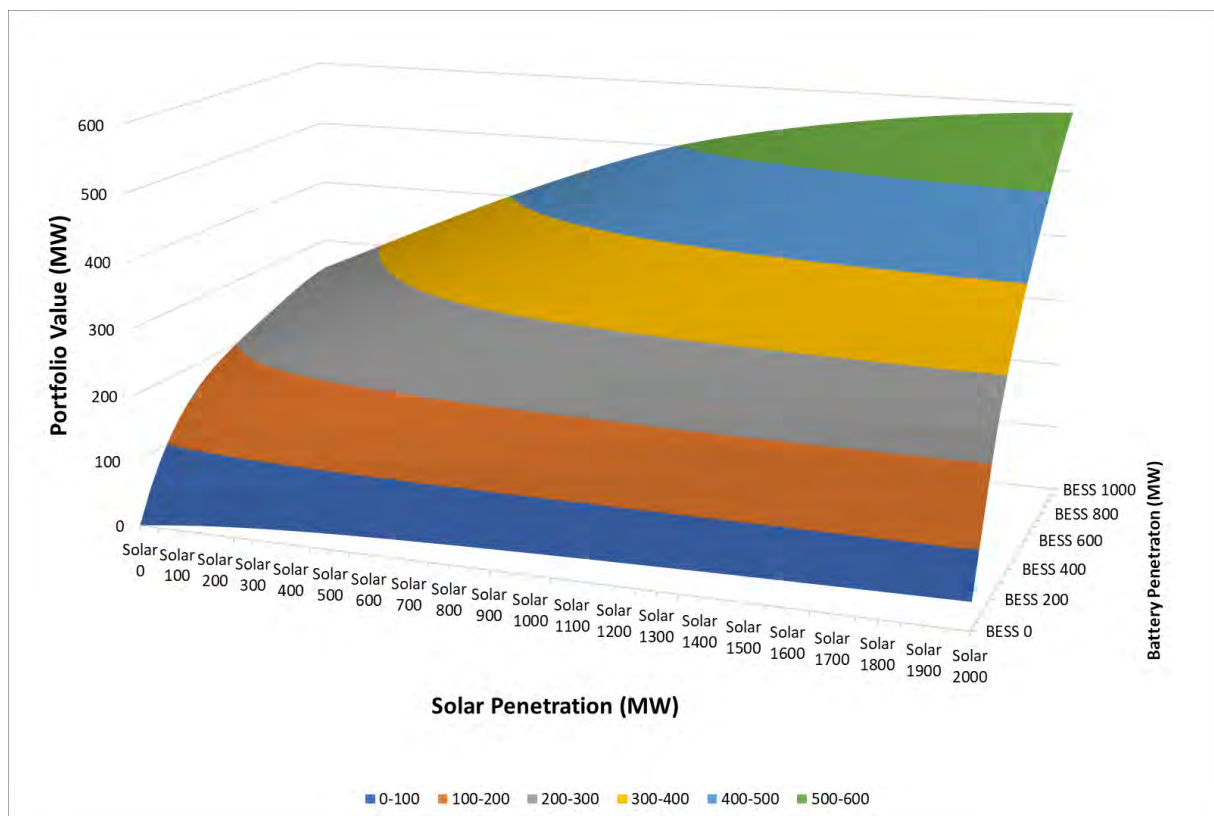


Figure 47. Portfolio Capacity Value at Zero Wind Penetration, Illustrative

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind.

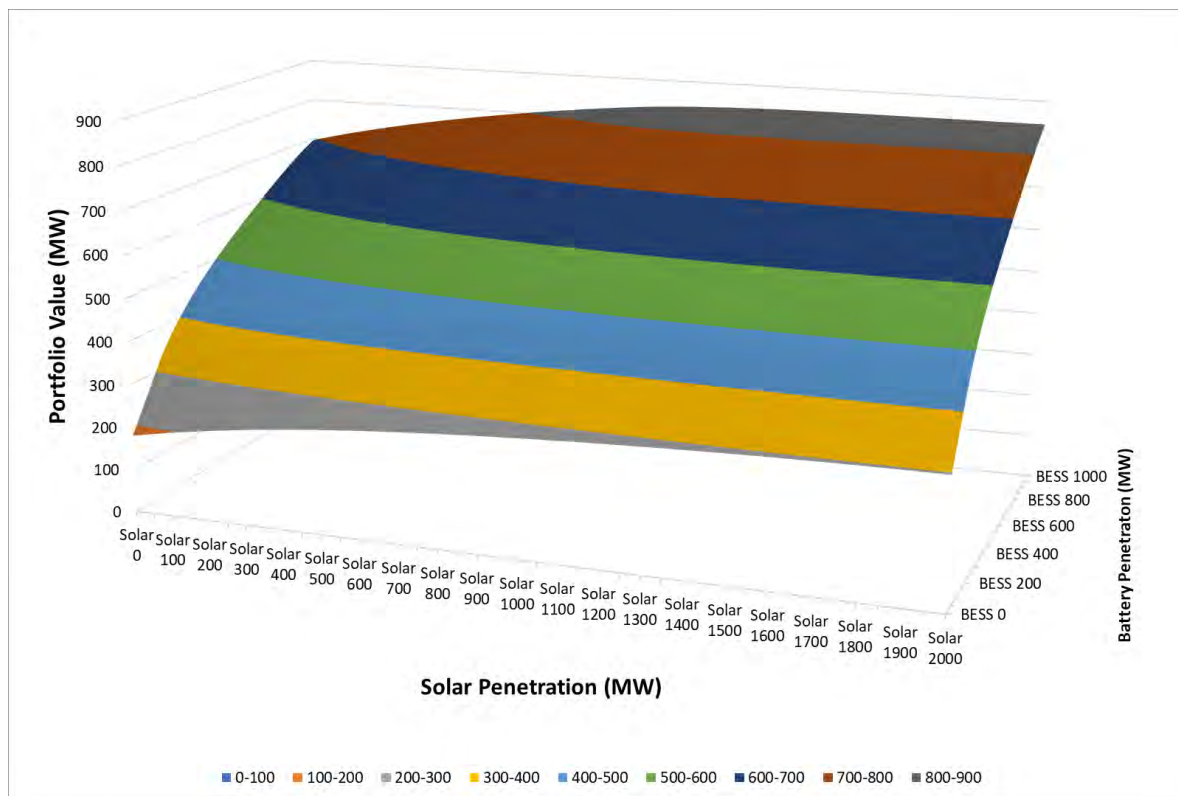


Figure 48. Portfolio Capacity Value at 2000 MW of Wind, Illustrative

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for

the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries. For example, in the solar chart, wind is at 1,000 MW and batteries are at 500 MW.

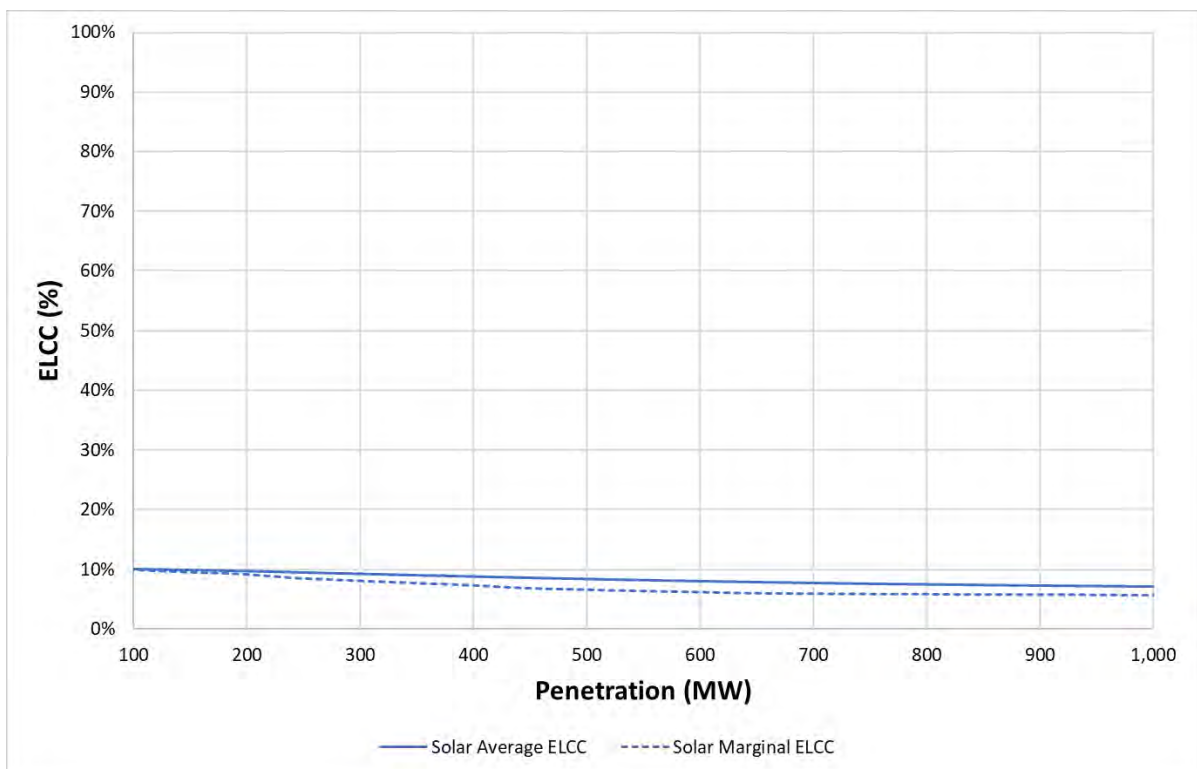


Figure 49. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

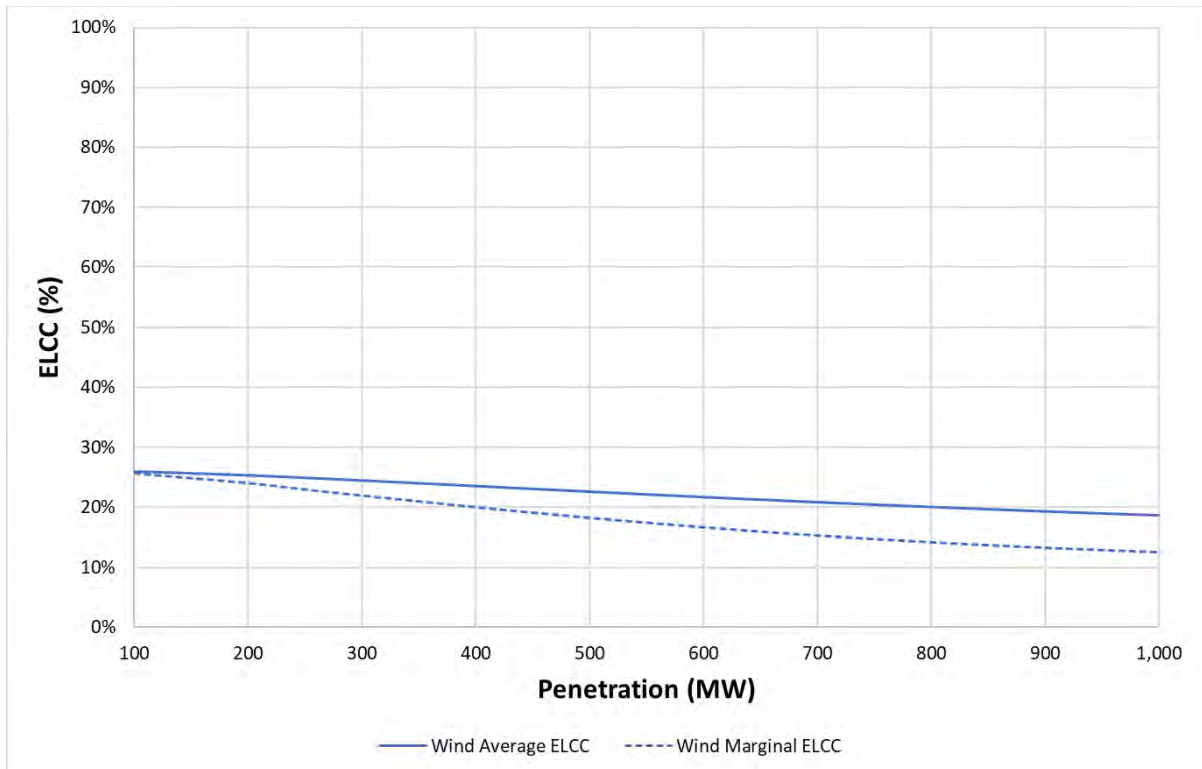


Figure 50. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery

Finally, the battery chart is shown below.

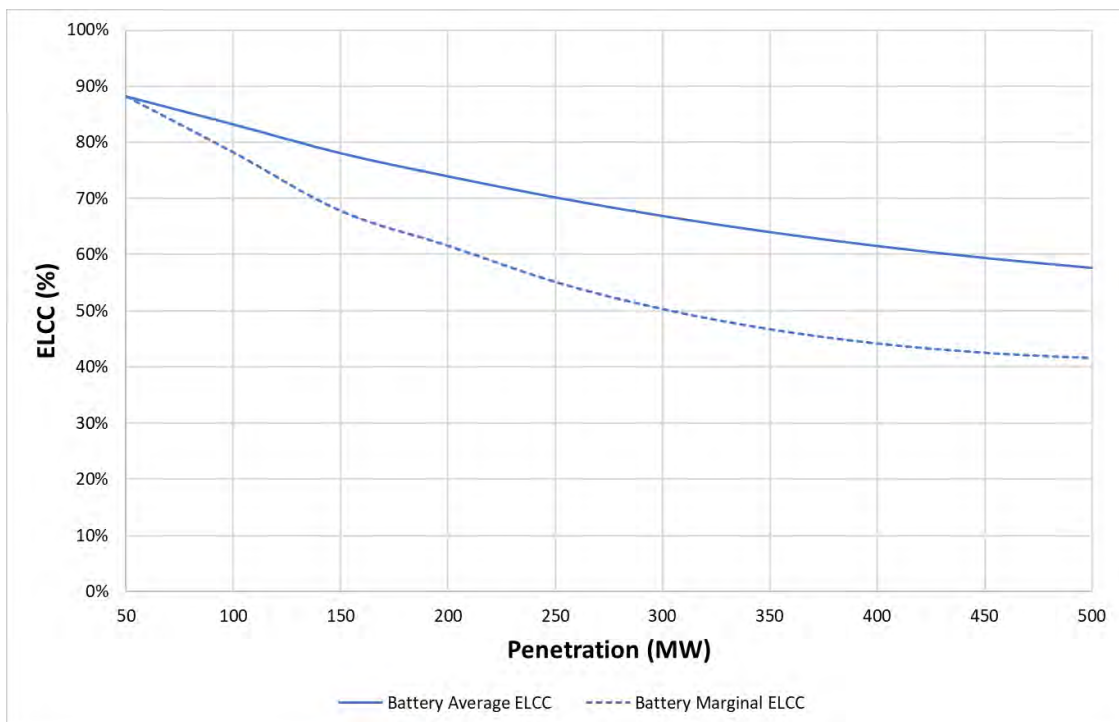


Figure 51. Battery ELCC at 1,000 MW of Solar and Wind

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including customer DG solar, EE, and 10-hour batteries.

To determine the ELCC of the customer DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the customer DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be “first in the queue” relative to the TSGT solar.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The figure below shows the average ELCC for 10-hour batteries for each of the three penetrations evaluated.

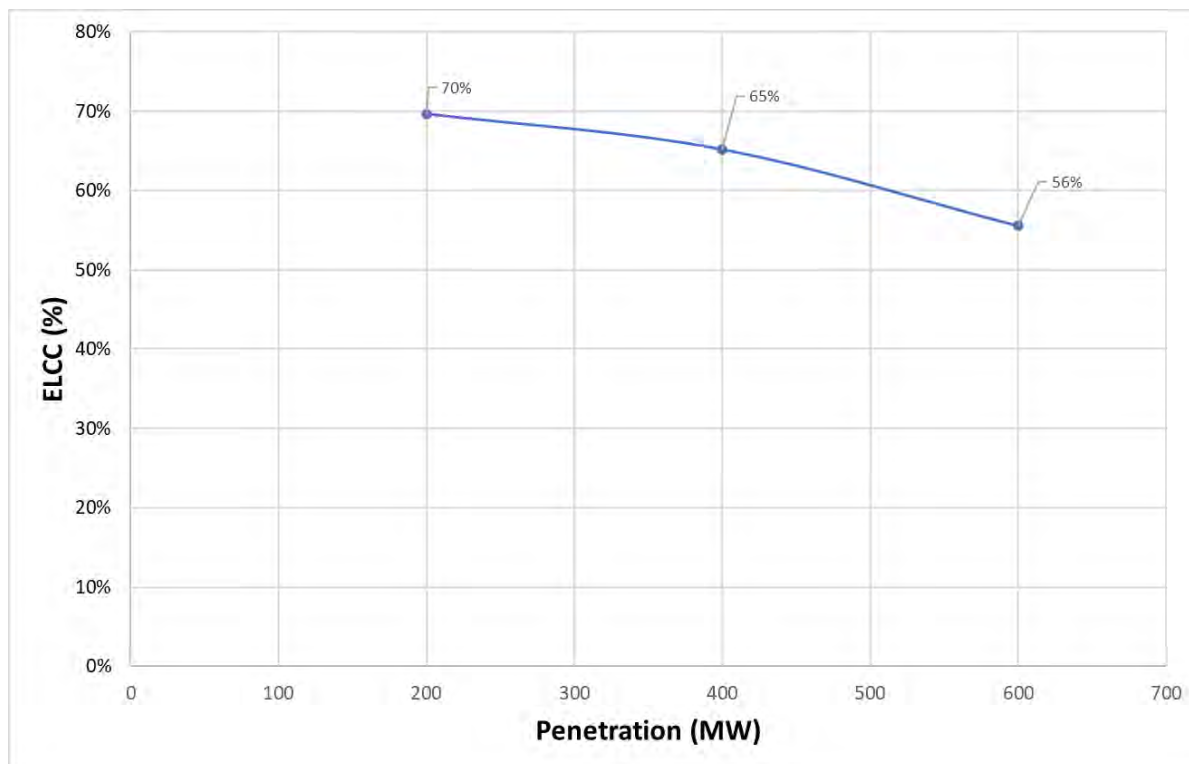


Figure 52. 10-Hour Battery Average ELCC

CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

APPENDIX

PCAP PRM Accounting

Neither ICAP nor UCAP truly reflect the reliability contributions of conventional resources (i.e., is not a perfect capacity equivalent) as evidenced by the ELCC calculations of the coal and CC resources in the results section above. Variability in outages results in some peak days having higher than average outages, resulting in a larger disparity between the true reliability contribution of the conventional fleet and the implied reliability contribution of EFORD. For TSGT in particular, shaft risk also contributes, because of the size of its coal and CC units relative to the peak load. Furthermore, UCAP does not stabilize the PRM against changes in renewable penetration. The most stable PRM accounting, therefore, utilizes PCAP accounting, in which all resources are discounted by their perfect capacity equivalent, or their ELCC. The table below shows the base case PRM assuming PCAP accounting. Only load is considered since EE would be treated as an ELCC modifier similar to resources.

Table 21. 2026 Base Case PCAP Accounting

Unit Category	MW
Total PCAP Capacity	2350.9
Coincident Peak Load	2221.3
Reserves	129.5
PRM	5.8%

Solar Modeling

The table below shows the GPS coordinates for each of the nine existing sites.

Table 22. Solar GPS Coordinates

Unit Name	GPS Coordinates
Alta Luna	32.57, -107.46
Axial	40.3, -107.77
Cimarron	36.47, -104.63
Coyote Gulch	37.04, -108.02
Dolores Canyon	37.71, -108.75
Escalante	35.42, -108.09
San Isabel	37.37, -104.48
Spanish Peaks 1	37.38, -104.46
Spanish Peaks 2	37.38, -104.45

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit PP: Department, Order No. 202-25-10 (Nov. 25, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.³ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ *Keeping the Lights On: Examining the State of Regional Reliability*, Before the H. Comm. on Energy and Com., S. Comm. on Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

of resources in PJM's interconnection queue.⁴ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."⁵ In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.⁶

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."⁷

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.⁸ The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

⁴ *Id.*; see also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

⁵ *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM. (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁶ *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx>.

⁷ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

⁸ Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,⁹ providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.¹⁰

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.¹¹ and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."¹² Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.¹³

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."¹⁴

⁹ See *Custom Data Download*, EPA CAMPD (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> "2025" and "June, July, August, September." The data can then be filtered to only include the Eddystone Generating Station.

¹⁰ See PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search range set to: effective from 06/01/2025 until 08/31/2025).

¹¹ *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

¹² *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

¹³ *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

¹⁴ *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint" *Id.*

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.¹⁵ PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.¹⁶ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”¹⁷ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report”¹⁸ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”¹⁹ PJM went on to explain, its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.²⁰ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”²¹ Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.²²

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”²³ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme” forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.²⁴

¹⁵ Four Rs Report at 2.

¹⁶ *Id.*

¹⁷ *Id.* at 16, Table 1.

¹⁸ *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

¹⁹ *Id.*

²⁰ *Id.* at 10-11. *See also id.* at 13 (“the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . .”).

²¹ *Id.* at 14.

²² *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.”).

²³ *Id.* at P 10.

²⁴ *Id.* at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.²⁵ In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."²⁶

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."²⁷ NERC assessed the PJM region at an elevated risk starting in 2026,²⁸ explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."²⁹ NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.³⁰

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."³¹ President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."³² The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."³³

²⁵ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

²⁶ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

²⁷ *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.

²⁸ *Id.* at 4.

²⁹ *Id.* at 7.

³⁰ *Id.* at 91-92.

³¹ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³² Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

³³ *Id.*

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."³⁴ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.³⁵ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.³⁶ Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.³⁷ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.³⁸

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."³⁹ Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

³⁴ See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁵ See PPL Corporation Q2 2025 Investor Update, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

³⁶ See Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

³⁷ Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy, at 28 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁸ *Id.* at 27.

³⁹ Asthana Test. at 4.

industrial growth.”⁴⁰ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁴¹ Therefore, Mr. Asthana stated that PJM “encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability.”⁴²

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁴³ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.⁴⁴

⁴⁰ *Id.*

⁴¹ *Id.* at 9-10.

⁴² *Id.* at 10.

⁴³ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

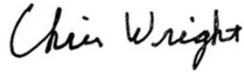
⁴⁴ 16 U.S.C. § 824a(c)(4).

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

- A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners

Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit QQ: Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit
Operating for Next 90 Days (Dec. 31, 2025)*

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12/31/25

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U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days

(December 31, 2025 – Westminster, Colorado) Tri-State Generation and Transmission Association and the other utilities that co-own Craig Generating Station Unit 1 received an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit’s retirement.

Separately, Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve, and Tri-State and the other co-owners will need to take the necessary steps to repair the valve in a timely manner.

“Tri-State has a policy of 100% compliance, and we will work with Unit 1 co-owners, and federal and state governments to determine the most cost-effective path to that end,” said Duane Highley, Tri-State CEO. “We are continuing to review the order to determine what this means for Craig Station employees and operations, and the financial impacts. As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options.”

As a result of the order, retaining Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State is continuing to review the order to determine how best to comply while limiting the costs to its members, and the impacts to its employees and operations.

The retirement of Craig Unit 1 was specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits, and the Regional Haze State Implementation Plan put in place in 2016. Tri-State’s 2020 and 2023 Electric Resource Plan (ERP) modeling reflected the previously announced retirement date for Unit 1. The model results of the 2023 ERP showed adequate resources to maintain reliability on Tri-State’s system following the retirement of Craig Station.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1’s capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Tri-State will share more information as appropriate when available.

About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

Contact

Amy Robertson, 303-254-3743, amy.robertson@tristategt.org

Mark Stutz, 303-254-3183, mark.stutz@tristategt.org

Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State’s plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State’s filings with the Securities and Exchange Commission. Tri-State’s expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management’s expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

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Tri-State Generation and Transmission Association
Office: 303-452-6111
1100 West 116th Avenue
Westminster, CO 80234

Mailing address:
PO Box 33695
Denver, CO 80233-0695

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Inc. Power supplier to the rural west.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit RR: Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)

Coloradoan.

Coloradoan.

1 coal plant open amid order



Rebecca Powell

Fort Collins Coloradoan

Jan. 6, 2026, 5:02 a.m. MT

Platte River Power Authority's general manager says he disagrees with a federal order requiring one of the coal plants it owns a stake in to remain open past its scheduled retirement and is waiting to learn what it might cost Fort Collins' wholesale electricity provider.

The U.S. Department of Energy on Dec. 30 issued an emergency order requiring Craig Unit 1 in Moffat County to remain available to operate for at least the next 90 days at the direction of the Western Area Power Administration or Southwest Power Pool West.

The plant was set to be retired on Dec. 31 after 45 years of operation, until that order was issued only a day prior.

PRPA is a joint owner of the plant with PacifiCorp, Xcel Energy, Salt River Project and Tri-State Generation and Transmission, which operates the facility.

PRPA owns 18% of the Craig 1 and 2 coal units.

The nonprofit provides wholesale electricity to Fort Collins Utilities. It is owned by four Northern Colorado cities: Fort Collins, Loveland, Longmont and Estes Park.

The Department of Energy's emergency order contends there is a shortage of electric energy and facilities in the Western Electricity Coordinating Council Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

Coloradoan.

Wright cites supply chain issues with building battery storage systems to help replace the energy from those retirements.

The emergency order also cited two executive orders from President Donald Trump. One declared a national energy emergency due to "insufficient energy production, transportation, refining, and generation." The other declares the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, like the expansion of AI data centers and domestic manufacturing.

But PRPA General Manager and CEO Jason Frisbie says PRPA does not need the Craig 1 unit because it has already replaced the energy that came from it.

"We have planned for the retirement of Craig Unit 1 for nearly a decade and have proactively replaced the capacity and energy from new sources," Frisbie said in a statement provided to the Coloradoan.

The joint owners have been planning for the plant's closure since 2016 "for economic reasons and to comply with numerous state and federal requirements," a Dec. 31 news release from Tri-State states. "This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement."

The state of Colorado is requiring utility providers to cut their 2005 carbon emissions by 80% by 2030.

The Craig 1 plant hadn't been operating since a mechanical failure occurred on Dec. 19, according to Tri-State. The problem will have to be fixed for it to become available for operations.

Coloradoan.

Duane Highley, Tri-State CEO, said the not-for-profit cooperative's membership will bear the costs of compliance "unless we can identify a method to share costs with those in the region."

"There is not a clear path for doing so, but we will continue to evaluate our options," Highley said.

Frisbie said PRPA is working to understand the impacts.

"While we disagree with the need to keep the plant open, we are working with the unit's operating agent, Tri-State Generation and Transmission, and the other owners to understand the compliance requirements and cost obligations of the emergency order," he stated.

PRPA is set to retire its last coal plant, Rawhide 1, located north of Fort Collins, at the end of 2029.

At that point, PRPA expects 88% of its energy will be from noncarbon sources. Today that figure is around 36%.

To help fill the void, PRPA is expected to invest \$600 million in construction of five aeroderivative gas turbines to provide electricity when wind and solar resources aren't available due to the weather.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit SS: Behr, P., *PJM to ratchet down projected AI power demand for eastern US*
(Jan. 6, 2026)

PJM to ratchet down projected AI power demand for eastern US

An updated analysis from the regional grid operator is expected to provide a reality check on data center growth.



BY: **PETER BEHR** | 01/06/2026 06:53 AM EST



A data center is seen under construction last year near the Susquehanna nuclear power plant in Pennsylvania. | Ted Shaffrey/AP

ENERGYWIRE | Across the U.S., energy policymakers and power grid operators have three broad goals at the top of their 2026 priority lists: enable AI dominance. Secure electricity supply. Keep power prices from spiraling.

But hitting those targets is challenged by a simple question that remains hard to answer: What's real and what's hype when it comes to data center demand for electricity?

Advertisement



The dilemma is front and center at PJM Interconnection, the nation's largest regional power grid, serving 67 million people in 13 states from the Atlantic coast to Chicago. Later this month, PJM plans to release an updated estimate of future electricity demand from large users. The report is expected to provide a serious reality check to the projections that developers and utilities make about future data center growth.

PJM Chief Operating Officer Stu Bresler said last month that PJM's overall power demand forecast for the year beginning in mid-2027 will be "appreciably lower" than current projections. PJM wants more evidence on how fast and how large new data centers can actually be built with shortages of chips, electronics and specialized construction teams.

Overestimating AI data center growth threatens to burden consumers with billions of dollars in excessive investments. Underestimating it increases risks of power shortages and blackouts while also undercutting [current U.S. leadership](#) as a developer of AI technology.

"At a time when utilities forecast hundreds or thousands of megawatts of growth, improving forecasts by even a few percentage points in the right direction — up or down — can impact billions of dollars in investments and customer bills," said David Rosner, a member of the Federal Energy Regulatory Commission, last year.

"Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible," Rosner said.

The most detailed [analysis](#) of future U.S. data center demand, issued a year ago by the Department of Energy's Lawrence Berkeley National Laboratory, could not get close to a precise prediction. Instead, it estimated the amount of the U.S. electricity output consumed by data centers in 2028 could range anywhere from 6.7 percent to 12 percent.

"We're all going around trying to solve a problem that we haven't even defined yet," said Caitlin Marquis, managing director of Advanced Energy United, a coalition of clean technology developers and energy users. "It's definitely worthwhile making sure that we know what we're planning for, because the costs of getting that wrong are significant either way."

But a clearer picture may be clouded by [consumer resistance](#) that puts some data center projects in doubt, and a fight in Washington over the power of the states to regulate AI.

President Donald Trump's executive order in October declares global AI "dominance" to be a national security imperative and seeks to impose White House control over state AI policymaking.

Governors from both political parties who head AI-leading states oppose Trump's moves. But governors have also been among the biggest AI cheerleaders because of the investment and tax dollars and jobs data centers deliver.

Acting on a directive from the Department of Energy, FERC is trying to [forge new rules](#) for assessing data center growth, with an uncertain timetable. PJM is a test case in the debate because of its concentration of existing data centers, the largest in the world by industry estimates.

Forecasts that 'defy logic'

PJM's long-term forecast projected an unprecedented surge in peak power use by data centers, factories and cryptominers that would require adding 32,000 megawatts of new generation, batteries, and demand response between 2024 and 2030. Of this, PJM expected 30,000 MW to come from data centers.

PJM's total generating capacity increased by only about 2,000 MW, or 1 percent, in the past year.

PJM's demand forecasts have been amped up by tech companies plowing billions of dollars into the AI race, joined by investor-backed speculators seeking to secure marketable sites for new centers, according to participants in PJM's review.

The prospect of skyrocketing electricity demand is already showing up on utility bills, according to PJM's independent market monitor, Joseph Bowring of Monitoring

Analytics. PJM charges ratepayers for incentive payments to generators to keep plants operating in future years, and those payments have escalated in the past two years because of expected data center construction.

Kent Chandler, a senior fellow at the R Street Institute and a former Kentucky utility regulator, said some PJM officials have acknowledged privately to him that the forecasts coming from utilities “sort of defy logic.”

“There just aren’t enough transformers and conductors and towers and engineers to accommodate the load growth that some of these utilities are proposing,” Chandler said.

That’s true not just within PJM, he said, but across the country.

Potential roadblocks to data center projects are detailed in a new analysis by ICF International. The consulting firm's software mapping program identifies potential data center sites based on key factors like the availability of grid power, favorable zoning and fiber-optic networks. The list of prime data center project locations is shrinking rapidly in Northern Virginia and many other areas, the ICF analysis shows.

“The challenge is knowing which data center is real versus a phantom project,” said Himali Parmar, ICF vice president for energy markets.

Developers are making multiple applications for the same project because it’s relatively cheap to do so, she said. Their applications are shielded by confidentiality agreements that developers demand and utilities accept rather than get in arguments with a potentially huge customer.

“Am I looking at 40 gigawatts of new load requests, or is it 70, or is it 80? That’s a challenge with this lack of transparency,” she said. “PJM does not know what’s coming its way.”

“Utilities have an inherent financial bias to overstate demand” in their forecasts, Chandler said. Strong demand forecasts can move utilities’ stock prices higher and result in increased investment in grid infrastructure that boosts financial returns, grid experts explain.

PJM officials “don't feel comfortable with what utilities are putting in,” Chandler said. “They don't necessarily have the information or expertise [to contradict the utility forecasts]. That’s something they're figuring out now,” Chandler added.

An advance clue to the revisions PJM is preparing may be data from the preliminary report on load growth PJM published last year — the report that will be updated this month.

It showed some utilities in PJM making significantly different assumptions about the reality of utilities' data center power demand.

An example is the contrast in load growth forecasts from Allentown, Pennsylvania-based PPL Corp., and Dominion Energy Inc., the Richmond, Virginia, power company. Dominion serves “data center alley” in Northern Virginia, the largest cluster of the facilities anywhere. Northeast Pennsylvania, PPL's territory, is seeing a rush of AI data center development proposals.

PJM published two forecasts. One was a “capacity” figure based on developers' unverified requests for transmission capacity within PJM to manage the load growth the developers are projecting. The second forecast was the utilities' own estimate of actual load growth.

PPL capacity forecast shows demand soaring more than 3,000 percent to 13,412 MW, in 2029. PPL's own demand estimate indicates that PPL expects about 80 percent of that new data center construction to be completed by 2029.

Dominion, on the other hand, which has the most experience within PJM by far with its track record of data center construction, said that only about 30 percent of the developers' power requests will actually materialize in 2029.

An analysis by ClearView Energy Partners said PJM is very likely to require better forecasting by utilities of data center demand. Its analysts noted that PJM board chair David Mills has suggested PJM could require state officials to review utilities' power demand forecasts and may call for scrutiny of forecasts by outside analysts looking at crucial supply-chain issues that could slow new data center construction.

“We would be better off if operators like PJM got the information directly from the customer and could have a back-and-forth with them to fully understand what they're doing,” Chandler said.

UP NEXT IN **THIS EDITION OF ENERGYWIRE**

Congress would boost oil and gas spending in fiscal 2026 package

BY IAN M. STEVENSON



UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit TT: Department, Order No. 202-26-21 (Mar. 30, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-21

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain³ assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.⁴ Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the “co-owners”.⁵ Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.⁶

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, “reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities.” In the 2025 LTRA, Colorado is included in the WECC Rocky Mountain assessment region.

⁴ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁵ Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), <https://prpa.org/generation/yampa-project/>.

⁶ As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as

Order No. 202-25-14, issued pursuant to FPA section 202(c) on December 30, 2025, required that Tri-State and the co-owners take all measures necessary to ensure that Craig Unit 1 continues to be available to operate for 90 days, until March 30, 2026. This order was based on my determination that emergency conditions existed within the WECC Northwest assessment area.

Specifically, I determined that the WECC Northwest assessment area faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.⁷ I determined that the continued availability of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁸ I determined that the continued availability of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.⁹ My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, “[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio.” The 2024 LTRA notes that:

[f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.¹⁰

employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁷ See, e.g., *Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy*, Order No. 202-25-14, at 1–2 (Dec. 30, 2025).

⁸ See, e.g., *id.* at 1–3.

⁹ See, e.g., *id.* at 3.

¹⁰ NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024, corrected Jul. 11, 2025), at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC’s Northwest-Central subregion, which included Colorado at the time, is “forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034.”¹¹ Meanwhile, WECC notes that most planned retirements are “baseload generation, such as coal, natural gas, and nuclear.”¹²

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-14 continue, both in the near and long term.¹³ The availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.¹⁴ While NERC assessed that the WECC Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,¹⁵ the area has an “[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35.”¹⁶ The LTRA also notes that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.¹⁷ Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTOs) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.¹⁸

The 2025 WECC Western Assessment of Resource Adequacy notes that “the West’s planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see

¹¹ WECC, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, <https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf>.

¹² WECC, *Western Assessment of Resource Adequacy*, <https://feature.wecc.org/wara/>.

¹³ Further, as noted in Order No. 202-25-14, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. See Order No. 202-25-14 at 1.

¹⁴ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

¹⁵ *Id.* at 7.

¹⁶ *Id.* at 160.

¹⁷ *Id.* at 161.

¹⁸ *Id.*

energy shortfalls as early as 2028.”¹⁹ The assessment goes on to say that “[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk.”²⁰ Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which “continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources.”²¹

Since 2019, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.²² Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),²³ accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.²⁴ In 2025, intermittent wind accounted for over 5,300 MW of Colorado’s electricity generating capacity.²⁵ Additionally, Colorado Public Utilities Commissioners

¹⁹ WECC, *Western Assessment of Resource Adequacy*, <https://feature.wecc.org/2025wara/index.html>.

²⁰ *Id.*

²¹ *Id.*

²² U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado*, (last accessed Mar. 18, 2026), <https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0>.

²³ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Conventional Steam Coal* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

²⁴ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

²⁵ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Onshore Wind Turbine* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.²⁶

Order No. 202-25-14 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²⁷ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²⁸ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁹

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³⁰ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

²⁶ RTO Insider, *Comanche 3 Repair Delay Raises RA Concerns in Colorado*, (March 26, 2026), <https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/>.

²⁷ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

²⁸ *Id.*

²⁹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³⁰ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”³¹ This statutory language constitutes a specific grant of authority to the Secretary to require the availability and operation of Craig Unit 1 when the Secretary has determined that such availability and operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through June 28, 2026.

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

- A. For March 31, 2026, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority,³² or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator,³³ as applicable.
- B. From April 1, 2026, SPP, Tri-State and the co-owners shall take all measures

³¹ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

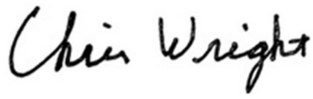
³² See EIA-930A 2024 Data, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930A 2024 SCH 2, the balancing authority (BA) Code for Craig is WACM. See EIA-930 data reference tables, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930 data reference tables BA Code WACM is associated with Western Area Power Administration—Rocky Mountain Region.

³³ SPP, *Western RC Services*, [https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20\(RC\),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project](https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20(RC),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project).

- necessary to ensure that Craig Unit 1 is available to operate.³⁴ For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.
- C. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A and paragraph B. SPP and Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.
 - D. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
 - E. By April 14, 2026, SPP and Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
 - F. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
 - G. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
 - H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.
 - I. This Order shall be effective from March 31, 2026 through June 28, 2026, with the exception of applicable compliance obligations in paragraph E.

³⁴ WAPA, *Southwest Power Pool RTO Membership Initiative*, <https://www.wapa.gov/about-wapa/the-source/key-topics/southwest-power-pool-membership/#:~:text=Since%202020%2C%20WAPA's%20Colorado%20River,FERC%20website%20under%20Docket%20No.>

Issued in Washington, D.C. on this 30th day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit UU: Tri-State, Request for Clarification and for Rehearing of Tri-State
Generation and Transmission Association and Platte River Power Authority
(Jan. 29, 2026)

Jennifer Quinn-Barabanov
202 429 8027
jqinnba@steptoe.com

Steptoe

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
202 429 3000 main
www.steptoe.com

January 29, 2026

Via Email

Secretary Chris Wright
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Alex Fitzsimmons, Director
Office of Cybersecurity, Energy Security, and
Emergency Response
1000 Independence Avenue, SW
Washington, DC 20585

Re: Craig Station, Order No. 202-25-7

Dear Secretary Wright and Mr. Fitzsimmons:

Pursuant to Section 313(a) of the Federal Power Act,¹ and Section 301(b) of the Department of Energy Organization Act,² Tri-State Generation and Transmission Association, Inc., and Platte River Power Authority hereby submit for filing the enclosed request for rehearing and for clarification.

Please contact me if you have any questions.

Respectfully submitted,

/s/ Jennifer Quinn-Barabanov

Jennifer Quinn-Barabanov
Michelle S. Kallen
Steptoe LLP
1330 Connecticut Avenue, N.W.
Washington, DC 20036
jqinnba@steptoe.com
mkallen@steptoe.com

¹ 16 U.S.C. § 825l(a).

² 42 U.S.C. § 7151(b).

**UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY**

In re Craig Order No. 202-25-14

) Order No. 202-25-14
)

**REQUEST FOR CLARIFICATION AND FOR REHEARING OF TRI-STATE
GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER
POWER AUTHORITY**

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Pursuant to Section 313(a) of the Federal Power Act,¹ and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),² and the applicable rules of practice and procedure,³ Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) hereby file this Request for Clarification and Rehearing of the Order No. 202-25-14 dated December 30, 2025 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate. Craig Unit 1 was scheduled to shut down by December 31, 2025.⁴

SUMMARY

Petitioners and the Department of Energy (DOE) share the goal of securing reliable and affordable electricity generation assets for their service areas' energy grid, including in the event of an energy emergency. For years, Petitioners have engaged in thorough, deliberate, and industry-leading resource planning to achieve this same end. Petitioners' resource planning ensures that the communities they serve are supported by electricity generation resources sufficient to respond to

¹ 16 U.S.C. § 825l.

² 18 C.F.R. § 385.713 (2024).

³ U.S. Dep't of Energy, DOE Rehearing Procedures, <https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures> (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214, 385.713.

⁴ Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

forecasted extreme weather events and demand growth, relying on coal, gas, dual-fuel, hydropower, solar, wind, and battery assets.

Petitioners will continue to work with DOE and other government agencies to secure reliable, affordable generation portfolios, but submit this request for clarification and rehearing because keeping Craig Unit 1 available to operate will not best meet DOE's goal of securing dispatchable electricity resources in the northwestern United States. Tri-State and Platte River, as member-owned and municipal public utilities, respectively, face unique challenges from the DOE's Order that lead them to file this request. The costs of compliance fall directly on their members and customers, who must now pay to respond to the DOE's finding that utilities in the northwestern United States have "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes," DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The members and customers must pay those costs even though neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order. For example, Tri-State has numerous members in New Mexico and Nebraska. Petitioners have already paid for and planned investments in the generation resources needed to secure reliable and sufficient capacity for their systems. The Order therefore imposes additional costs to Tri-State's membership and the communities served by Platte River.

Petitioners respectfully ask DOE to reconsider the Order and to work with Petitioners to find a more effective and affordable path forward, one that will not

delay retirement of Craig Unit 1. Petitioners continue to stand ready, willing, and able to work cooperatively with DOE and any other federal agencies to address energy emergencies in a manner that minimizes costs, promotes reliability, and complies with the law.

STATEMENT OF ISSUES

Pursuant to Section 313(a), Petitioners request clarification and, in the alternative, rehearing based upon the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical taking and a regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).
2. Because DOE predicated the Order on long-term concerns, Petitioners were deprived of the process due to them pursuant to the Administrative Procedure Act (APA) and the Federal Power Act (FPA), and the Fifth Amendment to the United States Constitution. This constitutes a violation of Petitioners' due process rights as guaranteed by the Fifth Amendment. *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991); *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970).
3. There is a disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives. DOE, therefore, did not establish that the Order "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373. It is, therefore, arbitrary and capricious.
4. The Order does not align with the statutory objectives of the Federal Power Act (FPA), because it requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,⁵ Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.⁶ Tri-State is wholly owned by its electric distribution cooperative and public power district members (Utility Members) and three non-Utility Members (Non-Utility Members)⁷ and was formed by its Utility Members for the purpose of providing the Utility Members with wholesale power and transmission services for resale to their retail customers.

Through their participation in the cooperative, the Utility Members serve retail customers across Wyoming, Nebraska, New Mexico, and Colorado. Some, but not all, of the Utility Members and their retail customers are located in the 2024 Western Electricity Coordinating Council (WECC) Northwest region.⁸ The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include suburban and rural residences, farms and ranches,

⁵ COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

⁶ *Tri-State Generation and Transmission Ass'n*, 170 FERC ¶ 61,221, at P 37 (2020).

⁷ Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

⁸ The boundaries of this region changed from 2024 to 2025, *see* note 24, *infra*.

and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities within the Western Area Power Administration's (WAPA) Western Area Colorado Missouri (WACM) balancing authority area, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities are included in the Western Power Pool reserve sharing pool. This pool facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State expects to participate in the Southwest Power Pool's (SPP) regional transmission organization, with respect to Tri-State's service in the WACM balancing authority area within the Western Interconnection, beginning in April 2026.

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C.

§ 824(f). Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is headquartered in Fort Collins, Colorado. At Platte River's main generating facility, Rawhide Energy Station, Platte River has one coal-fired power plant, Unit 1, with a nameplate capacity of 280 megawatts (MW), as well as five natural gas-fired units with a total capacity of 388 MW. Platte River also purchases 297 MW of wind energy and 202 MW of solar energy through long-term power purchase agreements and is a preference customer of WAPA's Colorado River Storage Project and Loveland Area Projects, providing up to 78 MW of hydropower. Platte River is a partial owner of two additional coal-fired units, Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River plans to participate in SPP's regional transmission organization beginning in April 2026.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates

Craig Unit 3. Together, these units are transmission-interconnected to the broader power grid and supply electricity into Western energy markets.

As part of its resource plan to address the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to curtail output from Axial Basin when all facilities are generating at or near full output due to limited transmission capacity.

As a result of changed market conditions and state and federal requirements, Unit 1 has been scheduled for retirement since 2016, and Units 2 and 3 have been scheduled for retirement since 2020, beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. A retirement date for each Craig unit is now specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits.⁹ In 2016, Craig Unit 1's retirement date was adopted into what was then Colorado Air Quality Control Commission Regulation No. 3 on Stationary Source Permitting and Air Pollutant Emission Notice Requirements and the Regional Haze State Implementation Plan, the latter of which was approved by EPA in 2018.¹⁰

⁹ COLO. CODE REGS. 1001-27.

¹⁰ *See Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan*, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine plans to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand of the Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand of the Craig Unit 2 through its planned retirement date.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has averaged \$12.99 million annually.¹¹ By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners.

Control Div., *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016), <https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135>.

¹¹ Over the last ten years, the operations and maintenance cost to run Tri-State's share of Craig Unit 1 has averaged \$23.9 million annually (inclusive of coal cost and depreciation expense). Over the last ten years, the fixed operations and maintenance cost to run Platte River's share of Craig Unit 1 has averaged roughly \$2.3 million (exclusive of coal cost and depreciation expense) annually.

Operation and maintenance of Craig Unit 1 has been undertaken prudently to reflect the scheduled 2025 retirement. The Craig Unit 1 owners have deferred optional maintenance since 2019. Craig Unit 1 has had multiple breakdowns and required significant repairs to continue operating into 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs made in direct response to the Order.¹²

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14. The Order declared that “an emergency exists within the WECC-NW assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.” DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The Order predicated its emergency on (1) “increasing demand” and (2) “shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years.” DOE stated, “[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.” *Id.* at 3.

DOE predicated energy reliability concerns on the 2024 Long-Term Reliability Assessment (2024 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-NW assessment area, “which includes Colorado, Idaho,

¹² Tri-State Generation & Transmission Ass’n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), <https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days>.

Montana, Oregon, Utah, Washington, and Wyoming[.]” *Id.* at 1. DOE also pointed to the 2024 WECC Western Assessment of Resource Adequacy. The concerns included (1) greater “energy variability” due to the region’s use of wind and hydropower; (2) planned retirement of baseload generation facilities fueled by coal, natural gas and nuclear; and (3) projected regional load growth. *Id.* at 2.¹³

The Order required Tri-State and the other co-owners of Craig Unit 1 to:

1. Take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable;
2. Limit operation of Craig Unit 1 to the times and within certain parameters to minimize adverse environmental impacts;
3. Provide daily notification to DOE reporting whether Craig Unit 1 has operated in compliance with the Order;
4. Comply with applicable environmental requirements including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions;
5. Update DOE on measures taken or planned to ensure operational availability of Craig Unit 1 by January 20, 2026; and
6. File with the FERC Tariff revisions or waivers to effectuate the Order with rate recovery available pursuant to 16 U.S.C. § 824a(c).

Tri-State has already taken and will continue to take steps to comply with the Order. In coordination with the other co-owners of Unit 1, it timely submitted its

¹³ The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

update to DOE on January 20, 2026, describing the measures it has taken and plans to take to ensure operational availability of Craig Unit 1. Tri-State has submitted and continues to submit daily notification to DOE pursuant to the Order.

ARGUMENT

Petitioners seek rehearing and clarification on two fronts. *First*, the Order, as drafted, effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet Section 202(c)'s requirement for a reasoned finding that compels operation of Craig Unit 1 as the "best" solution to the identified emergency.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 largely because of the uneconomic nature of the facility, and Petitioners have taken numerous steps over the years to prepare for its closure. By mandating that Tri-State continue operating the facility on a sustained basis for months beyond its planned closure date, and thus directing its operations in a manner entirely inconsistent with Petitioners' own planned retirement of the facility, the Order effects an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the physical infrastructure of the facility and mandated a variety of changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

A taking is not prohibited so long as it provides just compensation, but this taking comes with no assured government compensation. FERC cost recovery shifts costs onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be complex procedurally and substantively and could leave material costs unrecovered from the Order’s putative beneficiaries. The Order gives Petitioners no constitutionally adequate avenue for just compensation.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, “private property [shall not] be taken for public use, without just compensation.” U.S. Const. amend. V. “When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation.” *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take a variety of forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, “[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking.” *Ark. Game & Fish Comm’n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to a property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings in “as complete a sense as if the Government held full title and ownership.” *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis,¹⁴ and in clear departure from Petitioners’ own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings that must be compensated. *Second*, even if not characterized as a government seizure of operations, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment, requiring staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1 as the facility’s operations deplete limited fuel reserves that were allocated to other units that remain operational and are needed for reliability—the depletion of these stockpiled reserves will require Petitioners to obtain replacement coal at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1’s operations could further impede Tri-State’s use of the nearby Axial Basin generating facility by constraining Tri-State’s ability to inject power from that facility onto the grid.

¹⁴ Petitioners note that other similar Section 202(c) orders, issued to other utilities and on similar grounds, have been repeatedly renewed. *See, e.g.*, DOE Order No. 202-25-3 (May 23, 2025), *renewed for 90 days by* DOE Order No. 202-25-7 (Aug. 20, 2025), *renewed for 90 days by* DOE Order No. 202-25-9 (Nov. 18, 2025). Petitioners are reasonably concerned that DOE Order No. 202-25-14 could be similarly repeatedly renewed.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,¹⁵ making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see, e.g., United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (holding that a government seizure of part of a leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; and (2) limit operation of Craig Unit 1 to

¹⁵ Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) (hereinafter “Rolsma (2024)”).

certain times and parameters to minimize adverse environmental impacts. Even the narrowest version of the measures necessary to ensure that Craig Unit 1 is available to operate include extensive repairs to Craig Unit 1’s physical facility and the ongoing employment of some share of approximately 130 staff to maintain the Craig facility, operate equipment, and remain ready to operate. The Order requires Petitioners to take these significant steps, unnecessary but-for the Order, for a prolonged period of time. This closely resembles the sustained mandate to operate that the *Pewee Coal* Court held was a taking.¹⁶

Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), <https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067> (describing how the “unconsented closure” of a coal-fired power station constituted a *per se* taking of the facility owner’s property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne*, 576 U.S. 351).

By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to the government’s instructions and mandating an

¹⁶ The *Pewee Coal* Court did not enjoin the government’s actions—the wartime emergency justified the government’s effort to keep coal mines operational. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is “entitled to the benefits and subject to the liabilities” of operating a facility it takes over).

unconsented re-opening of a non-operational facility—for not hours or days but months—DOE engages in a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, mandating that Petitioners make Craig Unit 1 ready for operations compels Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused. *Second*, operations require fuel, which compels Petitioners to deplete the Craig facility's limited fuel reserves intended for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender and exhaust coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. And *third*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating could constrain the ability of these resources to fully access the grid.

a. **Physical Changes to Craig Unit 1**

Bringing Craig Unit 1 back into service has already required modifications to the physical infrastructure on the site, beginning with repairs to Craig Unit 1's failed

Main Steam Stop Valves #1 and #2, and including additional maintenance to the unit's baghouse that had previously been deferred based on the unit's planned December 31, 2025 retirement. Petitioners must also perform emissions testing and other evaluations to ensure that Craig Unit 1 complies with applicable environmental requirements to the "maximum extent feasible while operating consistent with the emergency conditions." Order No. 202-25-14 at 4. Ongoing operations at the site will also require continual maintenance and staffing readiness, with the potential for further equipment failures that require repair and staffing (including overtime). And long before Craig Unit 1 was scheduled to retire, Petitioners both engaged in careful resource planning resulting in generation portfolios for the future that meet all member/customer needs, as well as planning reserve margins necessary to ensure reliable capacity in the event of extreme weather events and other emergencies, all based on the assumption that Craig Unit 1 would retire from service on December 31, 2025.

Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (citing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds*, *Cumbre Inc. v. State Compensation*

Ins. Fund, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to make significant repairs to a facility they had planned to imminently retire for good. This is the kind of taking described in *Furey*.

b. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.¹⁷ Before closing the Colowyo Mine, Tri-State stockpiled sufficient reserves to operate its share of the Craig Units until their respective retirements. The only practical source of fuel for Craig Unit 1 to maintain readiness after its planned retirement, and to make use of in the event of a dispatch, are Craig Units 2 and/or 3's previously acquired and allocated reserves.¹⁸

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public reliability objective. Under *Horne*'s reasoning, forced depletion of a

¹⁷ Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

¹⁸ The diversion of this coal will necessitate future purchases of replacement fuel at uncertain cost, thereby imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Tri-State to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies.

utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

c. Axial Basin

The 145 MW Axial Basin generating facility is in the same general location as the Craig Generating Station and relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure, a clear physical intrusion. This transmission limitation could lead to further physical intrusion by potentially forcing the curtailment of one or more of the other generation facilities to ensure that there was sufficient transmission capacity available for Unit 1 to comply with the Order.

B. DOE's Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point Nursery*, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986 (1984) (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 124 (1982), which evaluates regulatory takings based on: (1) the regulation's economic

impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action.

The Order constitutes a regulatory taking under this analysis. The Order levies substantial economic impacts on Petitioners through both direct maintenance costs and the disruption to Petitioners' planning with associated downstream costs. The Order also disrupts Petitioners' reasonable investment-backed expectations rooted in years-long resource and economic planning, and interferes with Petitioners' operations and their contractual and regulatory rights.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. As discussed above, Petitioners will necessarily incur a variety of operations and maintenance costs to ensure that Craig Unit 1 is ready and able to operate on request, with no economic benefit available from retaining the to-be-retired facility because it is uneconomic to operate.

Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1, while the other Craig Units are operating, can impede Tri-State's ability to dispatch its nearby Axial Basin generating facility. This in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible value). *See Ruckelshaus*, 467 U.S. at 1011 (trade secrets are property); *Cienega Gardens v. United States*, 331 F.3d 1319, 1329 (Fed. Cir. 2003) (option rights to prepay subsidized mortgage and exit affordable-housing program are property); *Casitas*

Mun. Water Dist. v. United States, 543 F.3d 1276, 1288–96 (Fed. Cir. 2008) (water capacity rights are property). Forced operations would prevent Petitioners from most efficiently and affordably managing the transmission and generation system.

2. Investment-Backed Expectations

“The regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed] expectations.” *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O’Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner’s choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners’ reasonable investment-backed expectations on several fronts. DOE’s use of Section 202(c) authority to address long-term predicted shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.¹⁹ The Order fundamentally alters DOE’s longstanding approach in a novel, untested way that could not be predicted from DOE’s actions until recently, a decade after Craig Unit 1’s 2025 retirement was announced. Petitioners could not have fairly anticipated DOE’s novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners’ reasonable expectations.

¹⁹ *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

Moreover, diverting coal from Craig Unit 1 to comply with the Order depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations. The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws,²⁰ disruption to these longstanding relationships disturbs Petitioners' ability to manage risk, engage in long-term planning, and maintain their reputations as reliable counterparties. Notwithstanding possible regulatory action, Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their investment-backed expectations.

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since. As is best practice, Petitioners engaged in extensive long-term planning with both government and private-sector partners, and Petitioners' plan to close Craig Unit 1 is part of a long-term plan to retire Unit 1 for economic reasons. Disruption of these long-term plans through a shorter-term Order upsets Petitioners' reasonable investment-backed expectations.

²⁰ Section 202(c)(3) does not define "environmental law" in this context and the scope of that term is untested.

3. Character of the Taking

The character of a governmental action is defined by “the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant’s prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented.” *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). “A ‘taking’ may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good.” *Penn Central*, 438 U.S. at 124 (citations omitted).

The character of the Order’s action further strengthens the case for a regulatory taking. As discussed in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that “private property [shall not] be taken for public use, without just compensation.” U.S. Const. amend. V. Whether compensation is “just” is measured by relation “both to an owner whose property is taken and to the public that must pay the bill[.]” *United States v. Commodities Trading Corp.*, 339

U.S. 121, 123 (1950). “The owner’s loss is measured by the extent to which governmental action has deprived him of an interest in property.” *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987).

There is no established process by which Petitioners will obtain government compensation for losses relating to the Order. Section 202(c) and its implementing regulations, namely 10 C.F.R. 205.376, suggest recovery through FERC rate-making processes, but nowhere does the Order guarantee Petitioners’ complete recovery.²¹ As one example of the complexity of this undertaking, WAPA and the Bonneville Power Administration, as Federal Power Marketing Administrations located within WECC-NW, are exempt from most FERC jurisdiction.²² It is not immediately clear how the FERC rate-making process could be used to secure cost recovery from utilities serving areas located within the scope of the emergency but over which FERC lacks jurisdiction.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. The duty to pay compensation for a taking runs to the government—“a takings claim requires just compensation from the government, not from a private third party.” *See*

²¹ Additionally, the terms of the Order could have substantive impact on Tri-State’s ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g., Tri-State Generation and Transmission Ass’n*, 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

²² Stating that “[n]o provision in this subchapter shall apply to, or be deemed to include, the United States.” 16 U.S.C. § 824(f) (2024).

Deutsche Bank Nat'l Trust Co. v. SFR Invests. Pool 1, LLC, Case No. 2:14-cv-001131-APG-VCF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016); *see also Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations). This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery. DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional frailties. While Petitioners share DOE's goal of ensuring that the Northwestern United States has reliable and affordable electricity, the Order misses the mark.

First, the Order violates Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. While emergencies sometimes allow the government to provide only post-deprivation process, the government must do more than reference the word “emergency”—rather, it must show that the *kind* of emergency that requires such fast-moving action has occurred. The Order's asserted

emergency is no such emergency. And the Order disrupts a considered resource planning effort.

Second, the Order does not meet the requirements of Section 202(c). It does not consider reasonable alternatives as required by Section 202(c), including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings including from objective, industry-leading forecasting methods. *Third*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.²³

A more deliberative process would, on the whole, work better to address DOE's concerns about the reliability of the electrical grid in the northwestern United States, and, in particular, the Mountain West. Petitioners stand ready to work with DOE to make their service area as reliable as possible and best serve their members and customers, doing so in a manner that is economically efficient.

A. The Order Violates Petitioners' Constitutional Due Process Rights and Disrupts Carefully Considered Reliability Planning

The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due

²³ As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although Petitioners take the position that the Order does not comply with the requirements of Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking even if the Order is determined to be unlawful. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

process of law.” U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, & 824p.

Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as an emergency tool meant to address fast-moving and unexpected situations. *Indus. Park Dev. Co. v. EPA*, 604 F. Supp. 1136, 1142 (E.D. Pa. 1985) (“[A]dministrative deprivation of [a] property interest violates the Constitution’s due process guarantees except in very narrowly circumscribed emergency situations.”). However, “[t]here is a relation between the kind of emergency and nature of the solution.” *Pa. Gas & Water Co.*, 427 F.2d at 577. Where, as here, the declared emergency does not involve immediate and concrete concerns (potentially in 2029 if new generation is not built as planned), a hearing is certainly feasible, and, absent a hearing, Petitioners are deprived of their right to due process. *See Indus. Park Dev. Co.*, 604 F. Supp. at 1145 (holding that “[u]nilateral administrative action . . . should be saved for cases of extreme emergency”); *Miller*,

945 F.2d at 353 (emergency insufficient to avoid need for pre-deprivation hearing, but concluding that sufficient hearing had occurred).

The Order’s emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event, such as unusually extreme weather or another plant’s sudden unplanned outage. Rather, the emergency articulated by the Order is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC Northwest assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Formal notice to the co-owners, moreover, was lacking. The Order’s imprecision on boundaries of the region at issue,²⁴ not only highlights the lack of immediate crisis, but also fails to give Petitioners proper notice of the precise contours of the emergency. Petitioners were, therefore, deprived of their constitutional right to notice and a hearing before the Order came into effect.

The effect of this deprivation is significant. Petitioners have carefully planned the retirement of the Craig facility—including Craig Units 2 and 3’s reliance on

²⁴ The Order relies on NERC’s 2024 LTRA, which discusses conditions throughout the sweeping and populous WECC Northwest assessment area—an area that includes “Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota[.]” See N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 127 (corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf. However, NERC’s more recent and more targeted 2025–2026 Winter Reliability Assessment from November 2025 shows that the new WECC-Rocky Mountain region—redrawn to better reflect local conditions than the vast and heterogeneous old WECC-Northwest region—has more than enough power to meet immediate winter needs. See N. Am. Elec. Reliability Corp., 2025 Winter Reliability Assessment (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. Craig Unit 1 and most of Petitioners’ service territory is located in the WECC-Rocky Mountain region.

stockpiled coal. Petitioners have also planned and invested to bring new generation online, such as the Axial Basin facility, to ensure reliability even as Craig Unit 1 is carefully retired. If the Order proceeds and Unit 1 runs, it deprives the other units of fuel. This undermines Petitioners' planning, imposes "reliability" costs on Tri-State's members and Platte River's ratepayers a second time, and disrupts the operation and economics of the other coal resources still operating. A more deliberative process with the required pre-deprivation hearing would have allowed Petitioners to work with DOE to address concerns about reliability and shape a more workable plan.

B. The Order Failed to Consider Reasonable Alternatives

DOE could have taken other steps to more effectively meet the energy emergency identified in the Order. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2029 time-horizon of the asserted emergency. This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue. *Pa. Gas & Water Co.* 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such

alternatives.”) (citation and footnote omitted). The Order reflects no consideration of alternatives, let alone a case for mandating Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious.

Compelling Craig Unit 1 to remain available to operate after its planned retirement date must be the “best” measure to address this long-term reliability concern across the region described in the Order. “[R]easonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions.” *Michigan v. EPA*, 576 U.S. 743, 753 (2015). This weighing process requires engagement with the factual record, as reflected in DOE regulations, which require applicants to provide extensive information related to operations and alternative courses of action.²⁵ These requirements reflect the understanding that Section 202(c) should only be used where unit-specific alternatives have been considered, applied, and deemed inadequate based on the facts on the ground. The record in this proceeding reflects that neither these facts nor any reasonable alternatives were considered in connection with the Order.

DOE’s need to consider alternatives, based on a clear factual record, is particularly important given Craig Unit 1’s status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance, and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives.

²⁵ See 10 C.F.R. § 205.373. The specified information includes “conservation or load reduction actions,” “efforts . . . to obtain additional power through voluntary means,” and “[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other ‘entities’ that may be directly affected by the requested order.” 10 C.F.R. § 205.373(g)–(i).

Further, the Order fails to consider how mandating Craig Unit 1’s continued operation interferes with Petitioners’ ability to invest in other generation capacity and therefore undermines the very ends that it purports to advance. For instance, the Axial Basin generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; if all three Craig units are operating, Craig Unit 1’s continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

A lawful exercise of the emergency powers contained in Section 202(c) required consideration of reasonable regulatory alternatives. For example, the Order does not explain why DOE or FERC could not proceed through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process. Proceeding with a notice of proposed rulemaking for consideration and final action would have minimal short-term risks and is appropriate to the timeline of the described emergency, which, by DOE’s supporting evidence, is predicted to occur no earlier than “in Summer 2029 onward” (because “the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed”).²⁶ Similarly, DOE could have evaluated whether it had authority to take proactive action to insure that “new resources” in the region are not “significantly delayed.”

²⁶ N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 128 (corrected July, 11 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

In the absence of such consideration, and the disclosure of the relevant rationale, Petitioners and the public “cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]” *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1’s continued operation was selected as the “best” solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it was contrary to law and an arbitrary and capricious exercise of agency authority.

C. The Order is Inconsistent with the FPA’s Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is “inconsistent with the statutory mandate” or “frustrate[s] the policy that Congress sought to implement.” *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance a variety of policy goals, including protecting consumers from “excessive rates and charges,” *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted); “maintaining competition to the maximum extent possible[.]” *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the “orderly development of plentiful supplies of electricity . . . at reasonable prices.” *NAACP v. FPC*, 425 U.S. 662, 670 (1976).²⁷

²⁷ “Recognizing the careful balance that the FPA strikes between federal and state regulation” FERC recently found that “states retain exclusive authority over . . . the generation mix.” *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (Dec. 18, 2025). Long-term economic and planning decisions regarding Tri-State’s resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. See *Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Resources, LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) (“[FERC] may regulate the transmission, but not the generation, of electricity[.]”).

The Order, by compelling an uneconomic unit to remain operational on the eve of its retirement, upends Petitioners' ability to plan their systems in an orderly fashion and to act with confidence in a competitive marketplace. Because the Order is at odds with the statutory objectives of the FPA, it is arbitrary and capricious.

CONCLUSION

Tri-State is a not-for-profit, member-owned cooperative and Platte River is a not-for-profit municipally owned joint action agency. Both utilities aim to work with government at all levels to best serve the communities to which they provide reliable and affordable energy. In that light, Tri-State has taken the steps necessary to plan for a reliable system that would have a planning reserve margin of at least 22% even with the retirement of Craig Unit 1, for which its Utility Members have paid. Platte River has likewise proactively developed resources that more than replace Craig Unit 1's energy and capacity to reliably serve its owner communities and meet the planning reserve margins SPP requires for its expanded western footprint (19% for summer; 40% for winter), and for which its owner communities have already paid.

The Order effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirement that DOE's chosen policy rationally "best address[es]" the stated emergency. Requiring Petitioners—not all of whom are located in the WECC Northwest region described by the Order—to suffer additional costs *and* uncertainty because of potential conditions created by utilities outside Petitioners' service area, is fundamentally unfair and harms affordability. Petitioners urge DOE to reconsider the Order.

Respectfully submitted,

/s/ Jennifer Quinn-Barabanov

Jennifer Quinn-Barabanov

Michelle S. Kallen

David Marcou

Alexander Langer

Micaela Hyams

STEPTOE LLP

1330 Connecticut Avenue, N.W.

Washington, DC 20036

Tel: (202) 429-3000

Fax: (202) 429-3902

Attorneys for Tri-State

Generation and Transmission

Association, Inc.

/s/ Sarah Leonard

Jennifer Hammitt,

Director of Legal Affairs

Sarah Leonard,

General Counsel

2000 E. Horsetooth Road

Fort Collins, CO 80526

Tel: (970) 226-4000

Attorneys for Platte River

Power Authority

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of January 2026.

1. Salt River Project
 - a. Michael.OConnor@srpnet.com
2. PacifiCorp
 - a. marie.durrant@pacificorp.com
3. Xcel Energy
 - a. mlarson@wbklaw.com
 - b. Matt.b.harris@xcelenergy.com
 - c. Tyler.n.smith@xcelenergy.com
4. Western Area Power Administration (WAPA)
 - a. SOCChiefComplianceOffice@wapa.gov
 - b. Klinefelter@wapa.gov
5. Rocky Mountain Region and Southwest Power Pool (SPP) West
 - a. psuskie@spp.org
 - b. tkentner@spp.org
 - c. cnolen@spp.org
6. Intervenors - Public Interest Organizations:
 - a. rrigonan@earthjustice.org
 - b. mlenoff@earthjustice.org
 - c. lcoleman@earthjustice.org
 - d. mhiatt@earthjustice.org
 - e. matt.gerhart@sierraclub.org
 - f. greg.wannier@sierraclub.org
 - g. tcarbonell@edf.org
 - h. tekelly@edf.org
7. Intervenors - State of Colorado
 - a. carrie.noteboom@coag.gov
 - b. gabby.falcon@coag.gov
 - c. robyn.wille@coag.gov
 - d. jessica.lowrey@coag.gov
 - e. sarah.quigley@coag.gov
 - f. Phalen.Kohlruss@coag.gov
 - g. Patrick.Witterschein@coag.gov

/s/ Micaela Hyams

Micaela Hyams

Steptoe LLP

1330 Connecticut Avenue, NW
Washington, D.C. 20036

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

)
)
)
)

Order No. 202-26-31

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

Exhibit VV: CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report,
filed on March 17, 2026, in Proceeding No. 26M-0028E

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

**2026 ELECTRIC RESOURCE
ADEQUACY ANNUAL REPORTS**

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PROCEEDING NO. 26M-0028E

**TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S
NOTICE OF 2026 RESOURCE ADEQUACY ANNUAL REPORT**

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), pursuant to §40-43-104(1)(a), C.R.S., respectfully submits this Notice of 2026 Resource Adequacy ("RA") Annual Report informational filing.

I. BACKGROUND

On or before April 1, 2026, Tri-State, as a load serving entity ("LSE"), is required under §40-43-104(1)(a), C.R.S., to provide the Colorado Public Utilities Commission ("Commission") a RA Annual Report identifying the generating resources and accredited capacity used to serve its Utility Members.¹ On January 1, 2026, the Commission opened Proceeding No. 26M-0028E to receive these reports.

II. TRI-STATE'S 2026 RA REPORT

Tri-State has complied with this requirement with Figure 1 and Table 1.² Tri-State's 2025 RA Annual Report has also been made available on Tri-State's website, here: <https://tristate.coop/resource-planning>.³

¹ The Colorado Resource Adequacy Act of 2023 became effective August 7, 2023 (House Bill 23-1039).

² Colorado Energy Office ("CEO") has requested that entities subject to §40-43-104, C.R.S. also complete a "Resource Adequacy Spreadsheet" to be returned to CEO by April 30, 2026. Tri-State intends to voluntarily respond to this request.

³ On January 11, 2025, Tri-State received guidance from CEO (pursuant to §40-43-104(3), C.R.S.) requiring each LSE to make its RA annual report available on its website and searchable by including "Resource_Adequacy_2026."

FIGURE 1 –LOAD AND RESOURCES

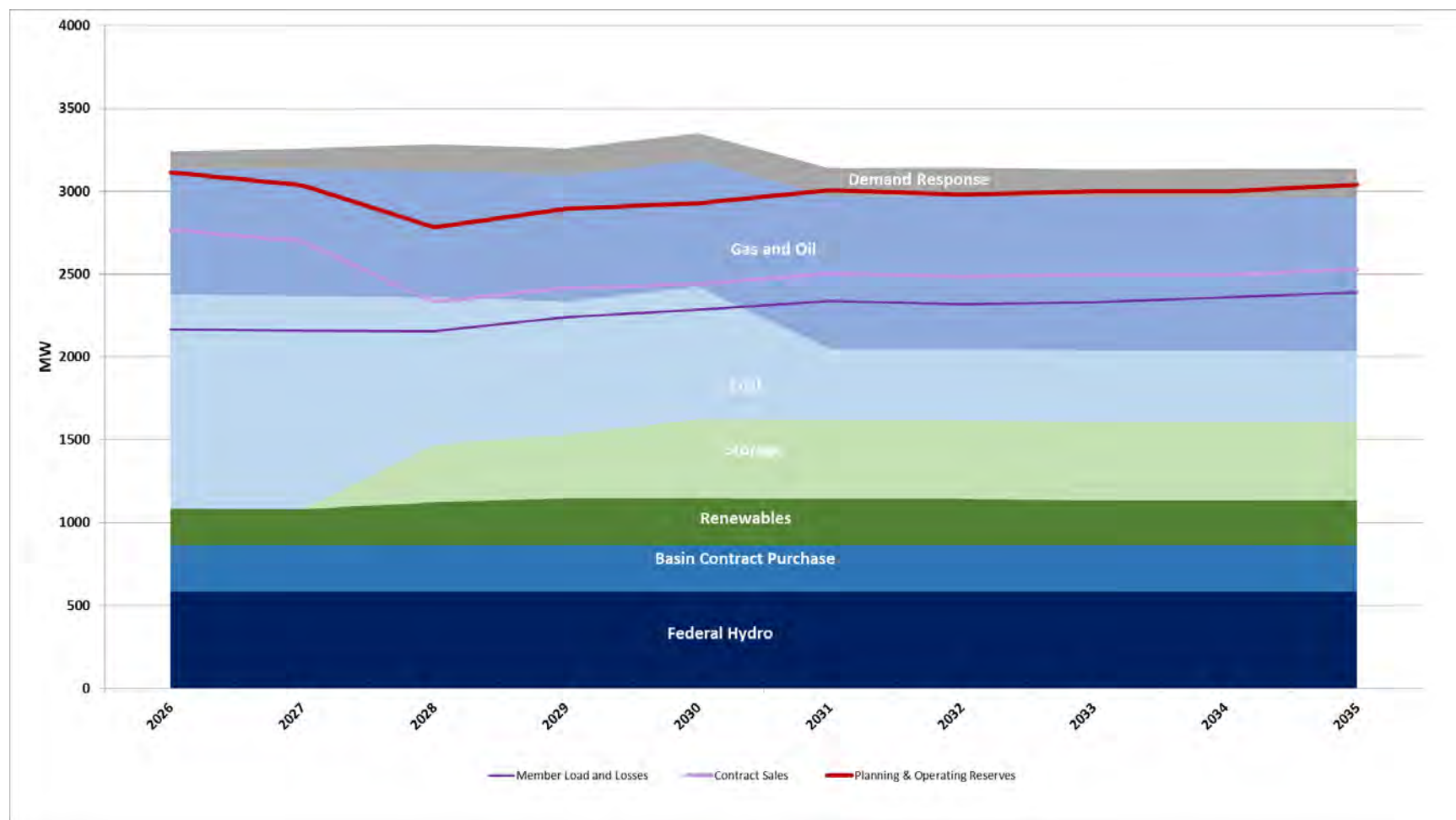


TABLE 1 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	584	584	584	584	584	584	584	584	584	584
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables ⁴	226	222	260	286	286	281	281	272	273	271
Demand Response	100	124	161	162	164	165	167	169	170	172
Coal Generation ⁵	1287	1286	888	800	800	431	432	431	432	431
Gas & Oil Generation ⁶	765	765	765	765	765	925	925	925	925	925
Storage ⁷	0	0	349	383	474	474	474	474	474	474
<i>Total Resources</i>	3239	3257	3285	3259	3351	3138	3141	3132	3136	3135
Member Load and Losses ⁸	2166	2160	2156	2241	2284	2337	2317	2332	2358	2390
Planning & Operating Reserves	348	341	451	476	489	505	498	502	502	511
Contract Sales	601	537	177	177	155	166	166	166	139	139
<i>Total Obligations</i>	2001	1971	1781	1865	1906	1957	1936	1949	1948	1978
Excess Resources	123	219	501	364	422	131	160	133	136	95

⁴ Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.

⁵ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

⁶ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

⁷ Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.

⁸ Western Interconnection Load.

Tri-State's report covers its Utility Members as LSEs, for the portion of their loads served by Tri-State,⁹ pursuant to §40-43-104(2), C.R.S.

In accordance with §40-43-104(1)(c), C.R.S., Tri-State understands that the Colorado Energy Office will, by July 1, 2026, utilize Tri-State's report and that of other LSEs to create an aggregated statewide report.

Submitted this 17th day of March, 2026.

WOMBLE BOND DICKINSON (US) LLP

/s/ Dietrich C. Hoefner

Dietrich C. Hoefner, #46304

Claire Tate, #62231

1601 19th Street, Suite 1000

Denver, CO 80202

Phone: (303) 623-9000

Fax: (303) 623-9222

Email:

Dietrich.Hoefner@wbd-us.com

Claire.Tate@wbd-us.com

and

Elizabeth C. Stevens, #45864

Senior Regulatory Counsel

Tri-State Generation and

Transmission Association, Inc.

1100 W. 116th Ave.

Westminster, CO 80234

Phone: (303) 254-3534

Email: liz.stevens@tristategt.org

**Attorneys for Tri-State Generation and
Transmission Association, Inc**

⁹ Tri-State expects that certain Utility Members that are exiting Tri-State membership may supply separate RA Annual Reports, to the extent applicable.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit WW: NERC, Long-Term Reliability Assessment (Jan. 2026)

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



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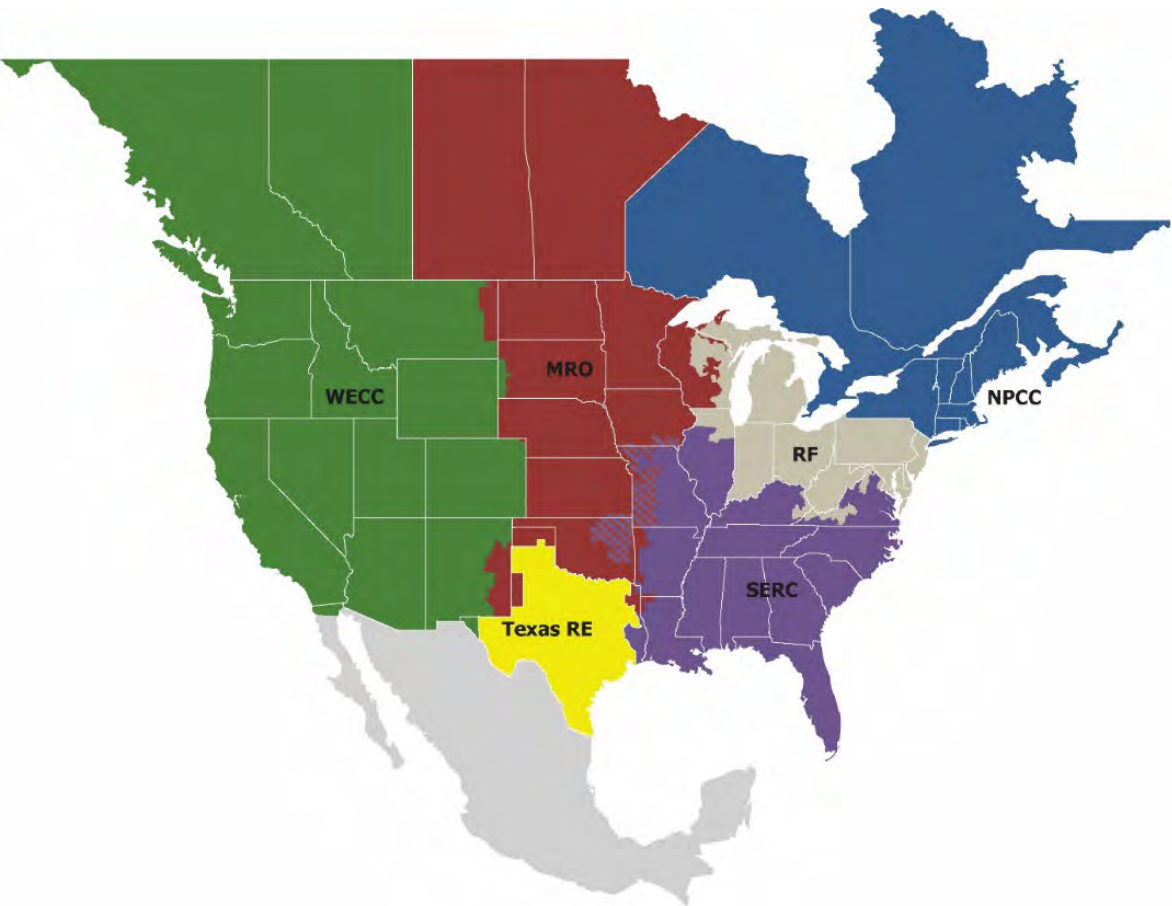
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC’s regulations provides that “The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission.”

The *Long-Term Reliability Assessment* (LTRA), along with NERC’s other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The [Summer Reliability Assessment](#) (SRA) and [Winter Reliability Assessment](#) (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts [special reliability assessments](#) on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- **State of Reliability Report (SOR):** The [SOR](#) contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO

Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.

- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the [ERO Event Analysis Program](#). This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC’s [website](#).

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see [Preface](#)) on an assessment area basis (see [Regional Assessments Dashboards](#)) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The [Reliability Assessment Subcommittee](#) (RAS), at the direction of NERC’s [Reliability and Security Technical Committee](#) (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO’s Rules of Procedure¹ and Title 18, § 39.11² 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.

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

- 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

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.

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](#).

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](#).

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.

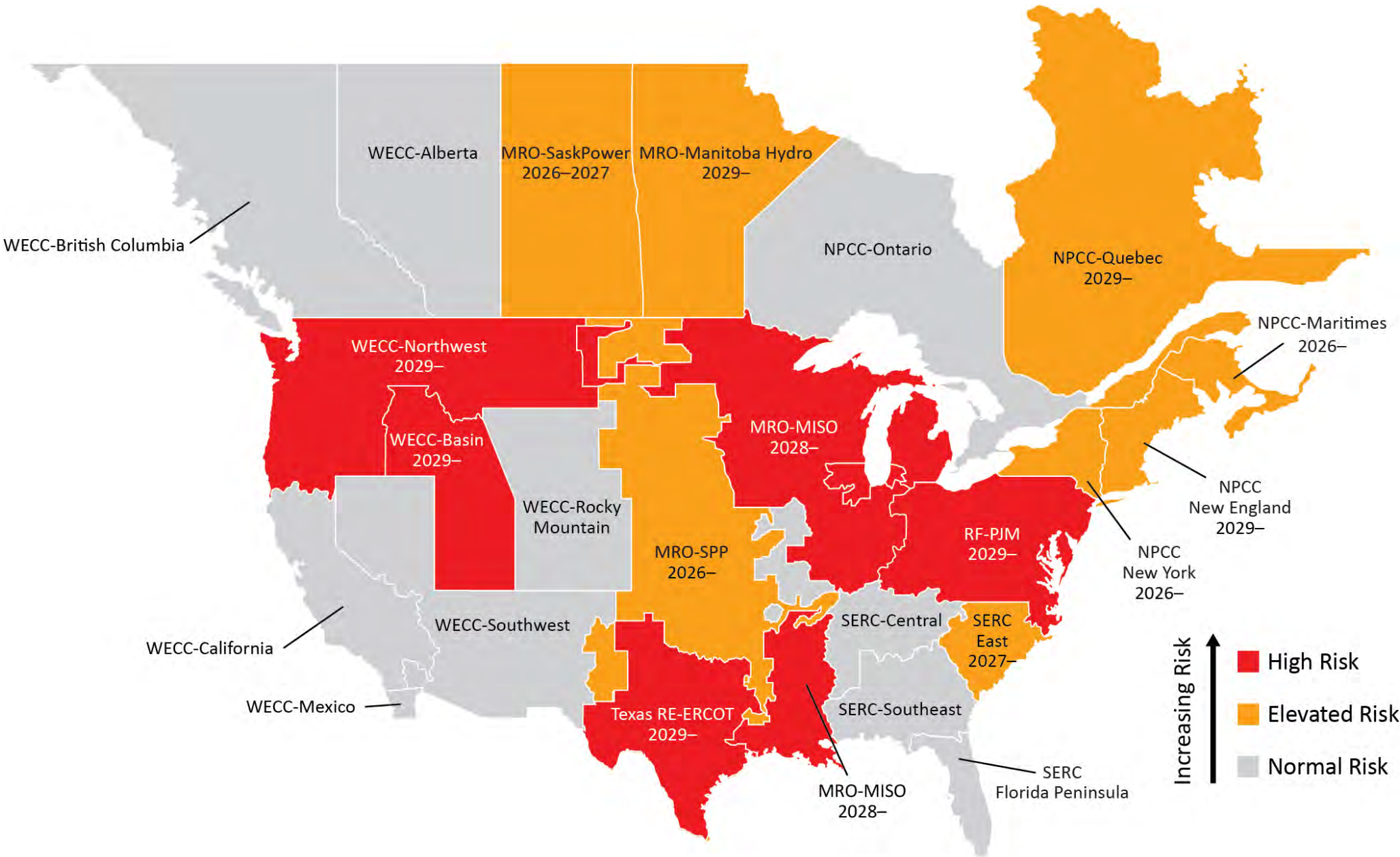


Figure 1: Risk Area Summary 2026–2030

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 <i>Expedited Resource Addition Study</i> (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 <i>LTRA</i> . 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 <i>Expedited Resource Adequacy Study</i> is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the 2024 <i>LTRA</i> , 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 <i>Q3 Star Report</i> .
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 <i>LTRA</i> 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 <i>LTRA</i> , 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 Plan¹⁰ 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 extreme¹⁴ 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.

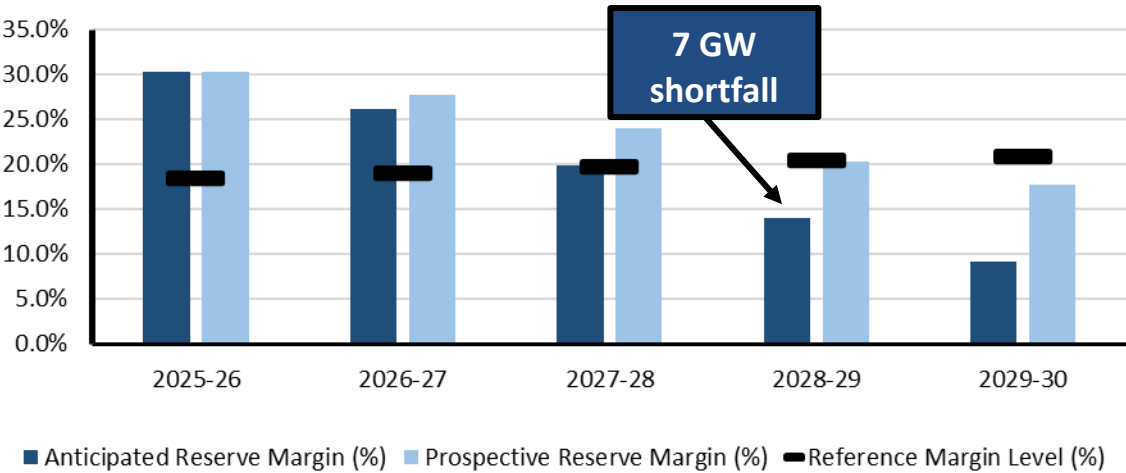
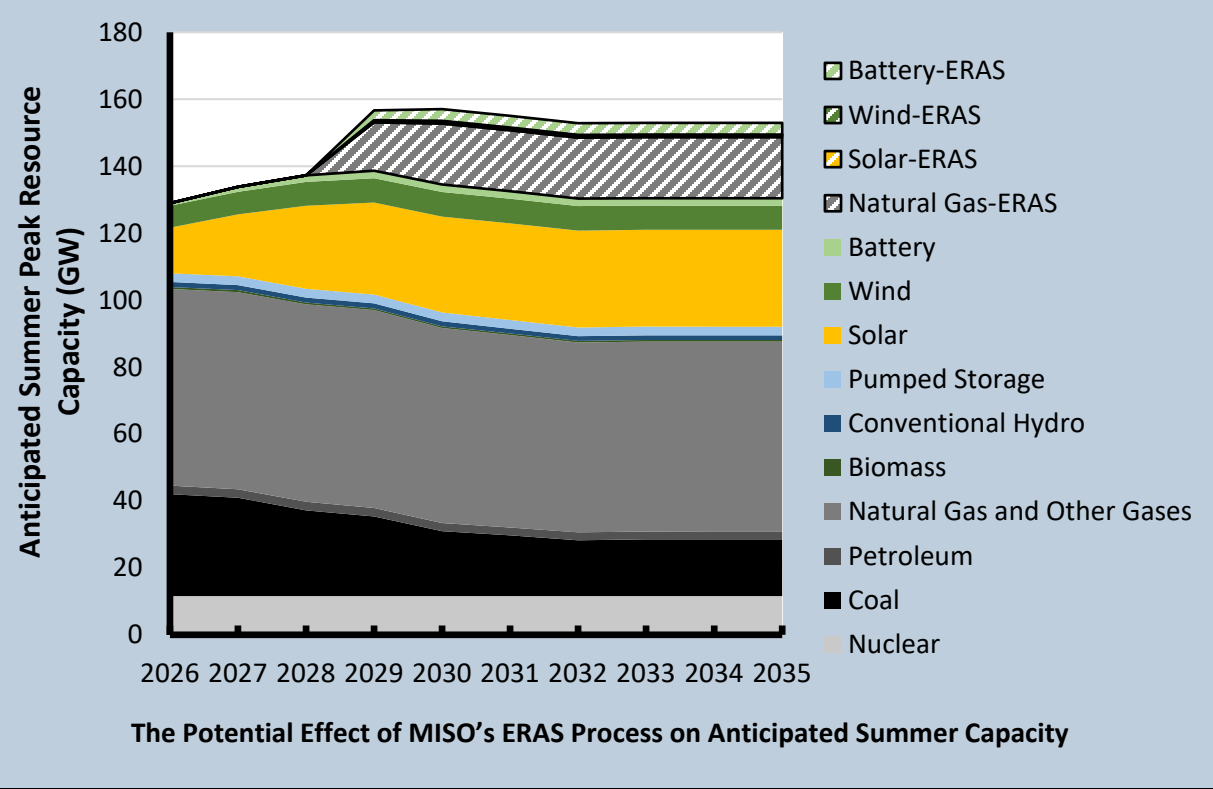


Figure 2: MISO Winter Planning Reserve Margins

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.

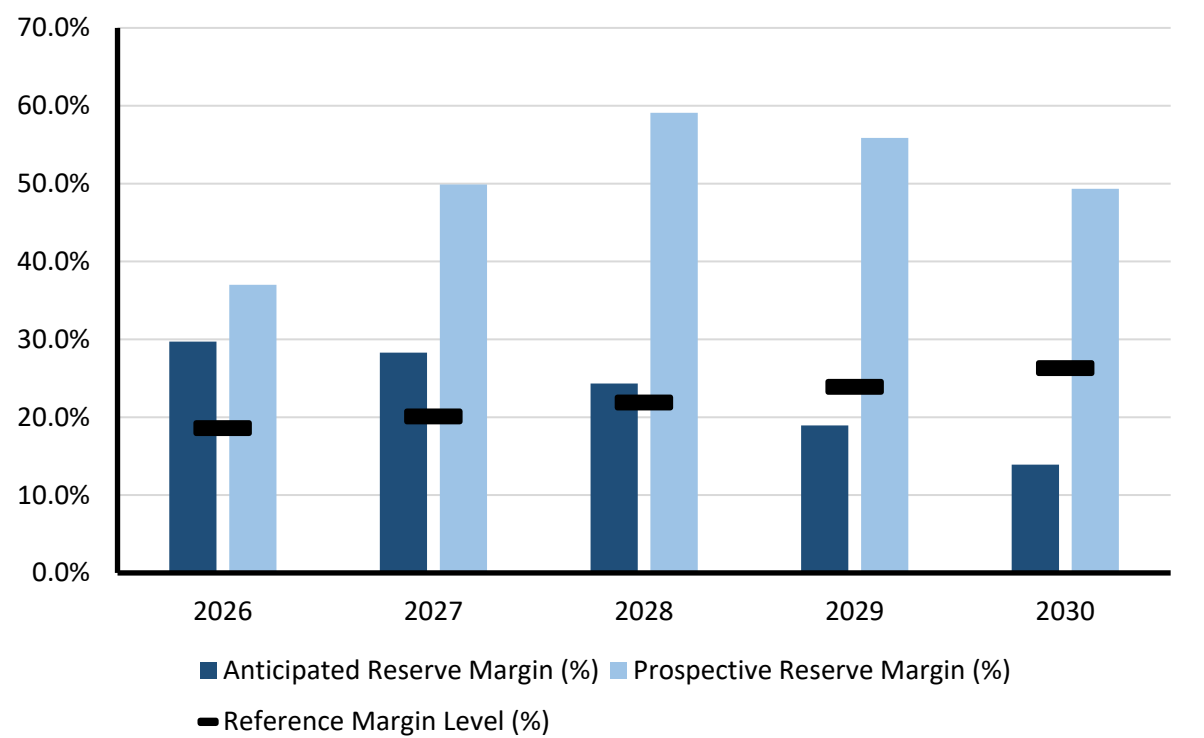
The timing of FERC’s approval of MISO’s ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in 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.



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](#)).



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](#)).

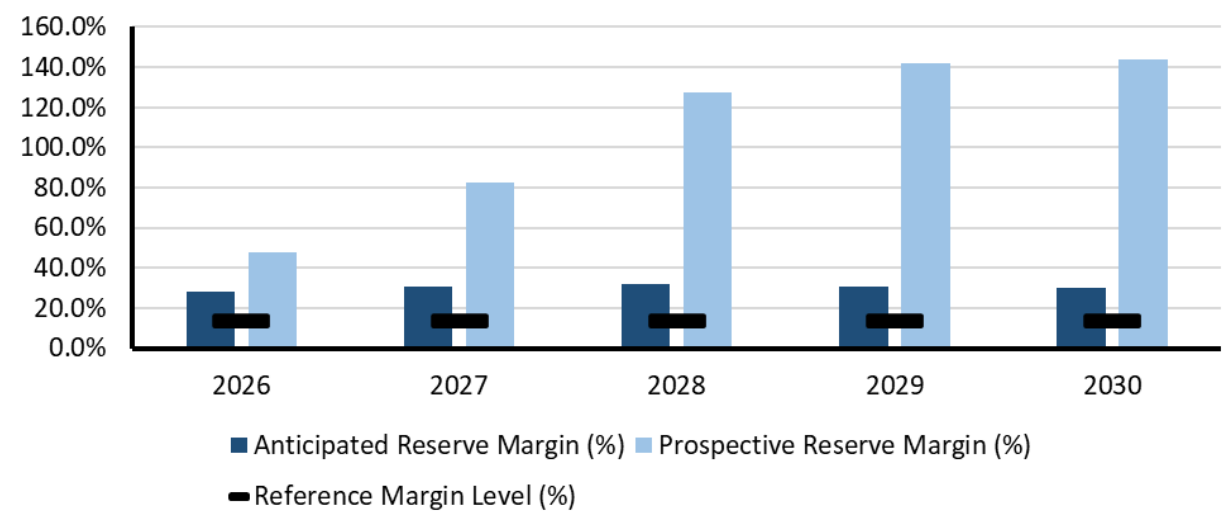


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

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

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.

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

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.

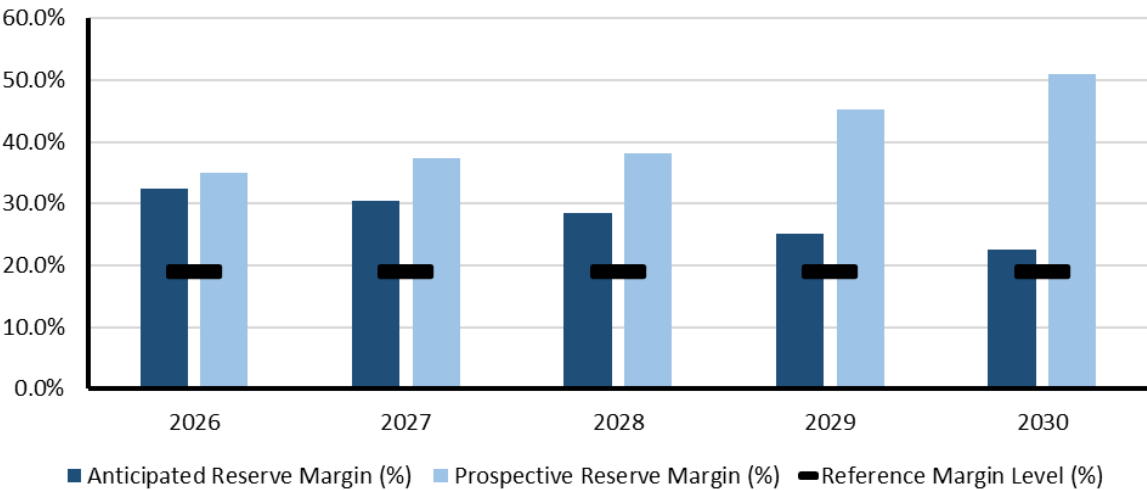


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

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.

¹⁸ Additional details available in the report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/>

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			

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.

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

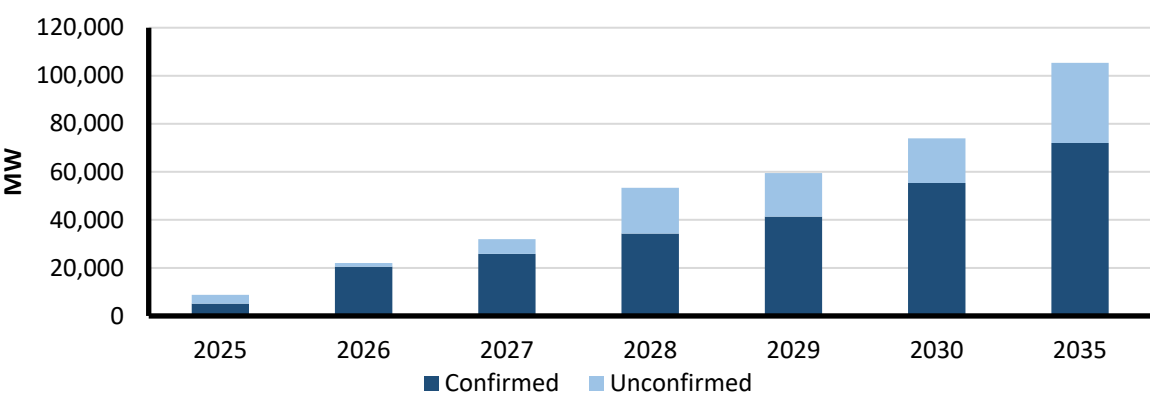


Figure 6: Projected Generation Retirement Capacity Through 2035

[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.

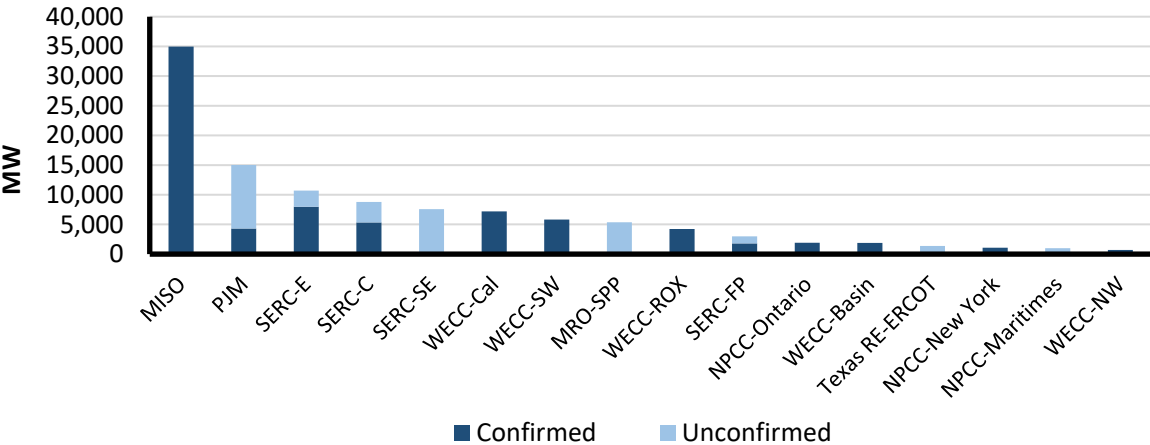


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

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](#).

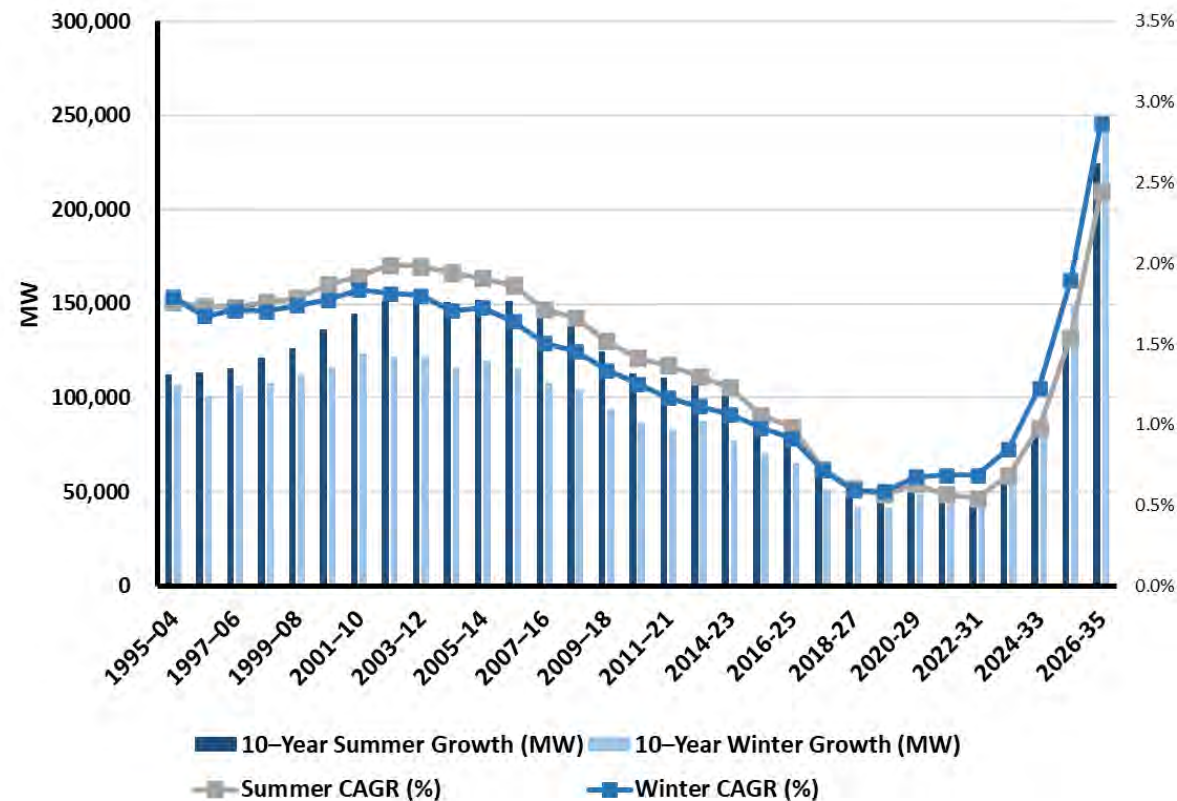


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

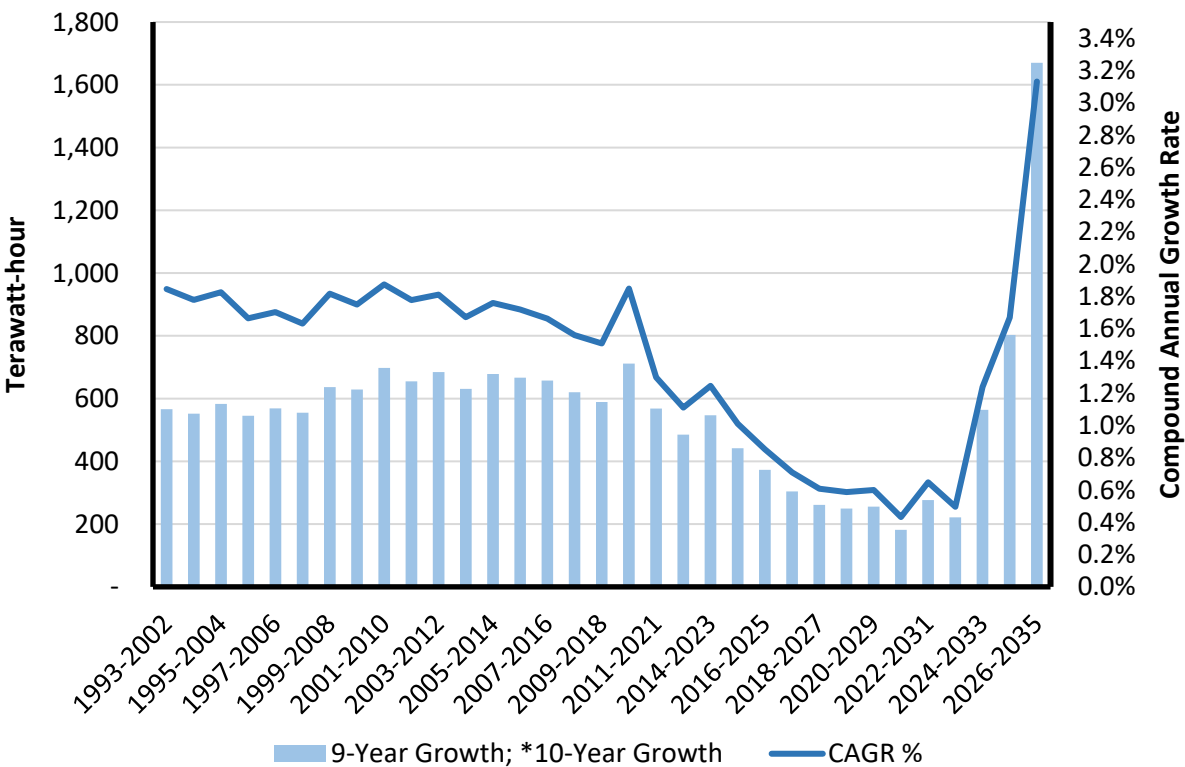


Figure 9: Net Energy for Load Growth and Rate Projections

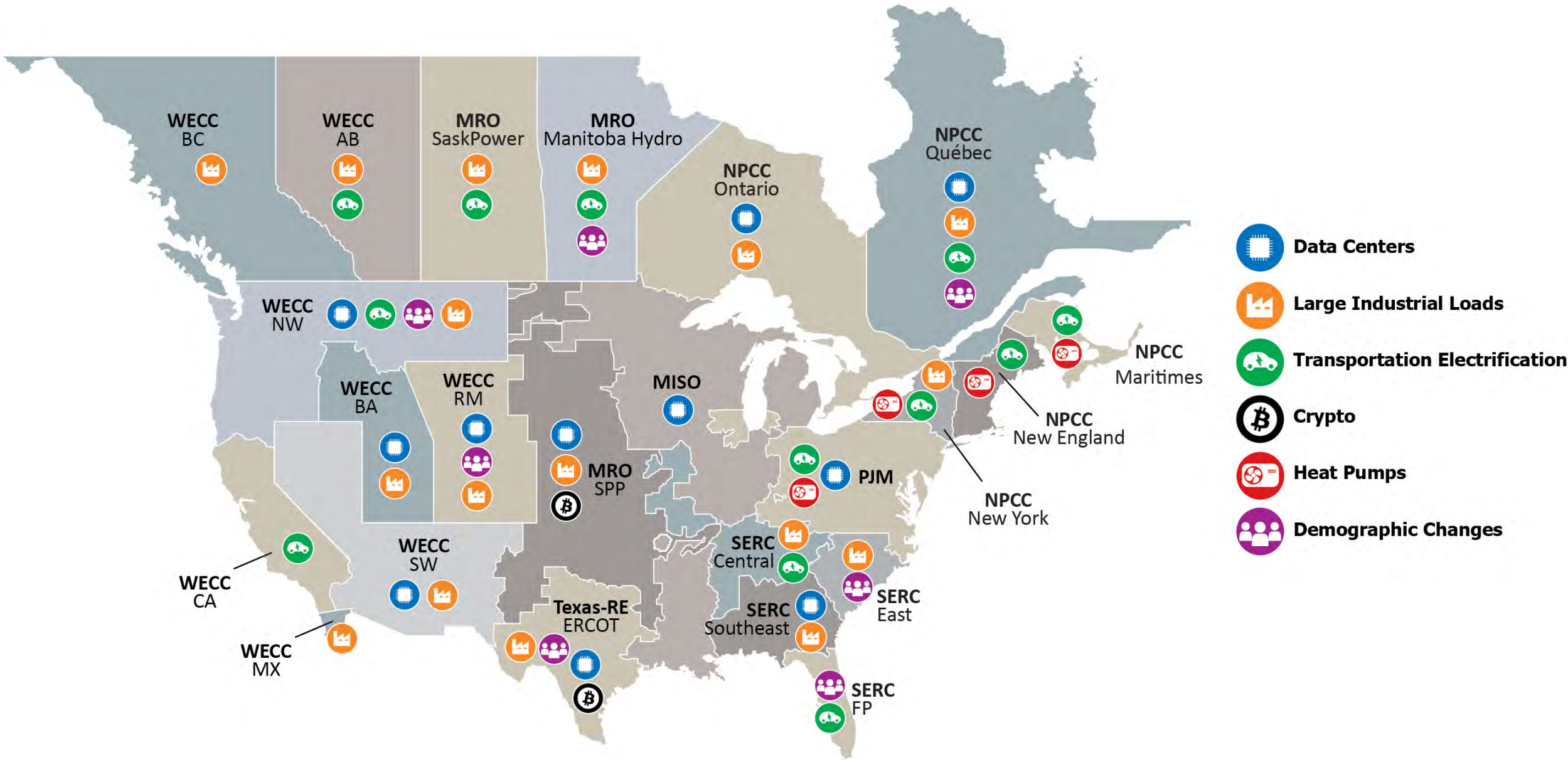


Figure 10: Primary Demand Drivers by Assessment Area

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.

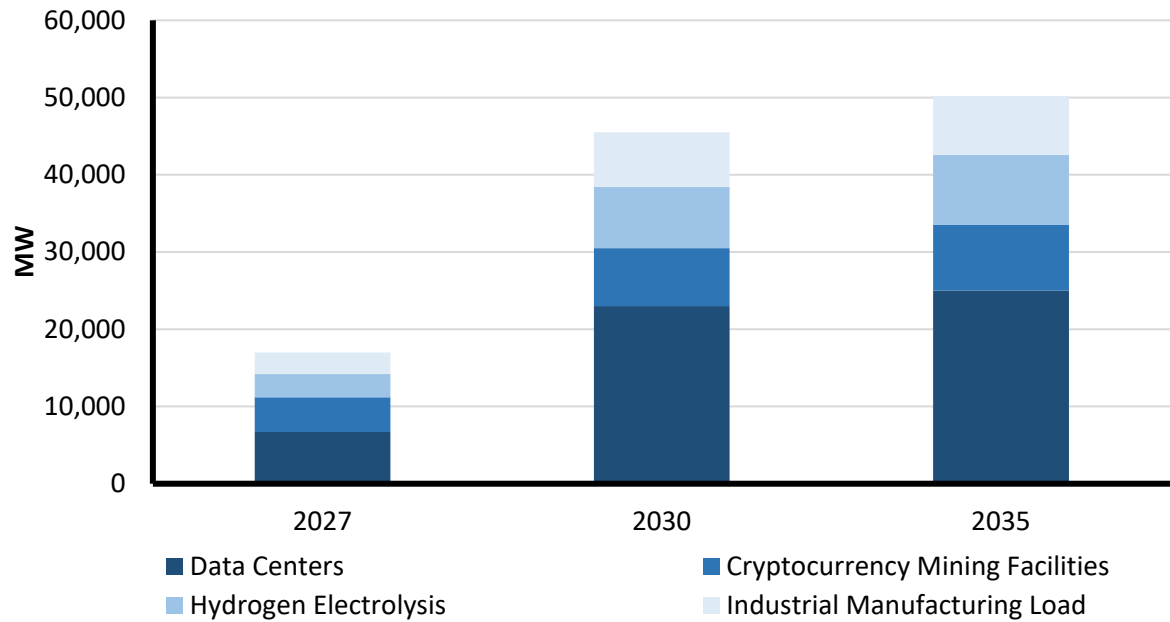


Figure 11: Large-Load Projection Breakdown in ERCOT

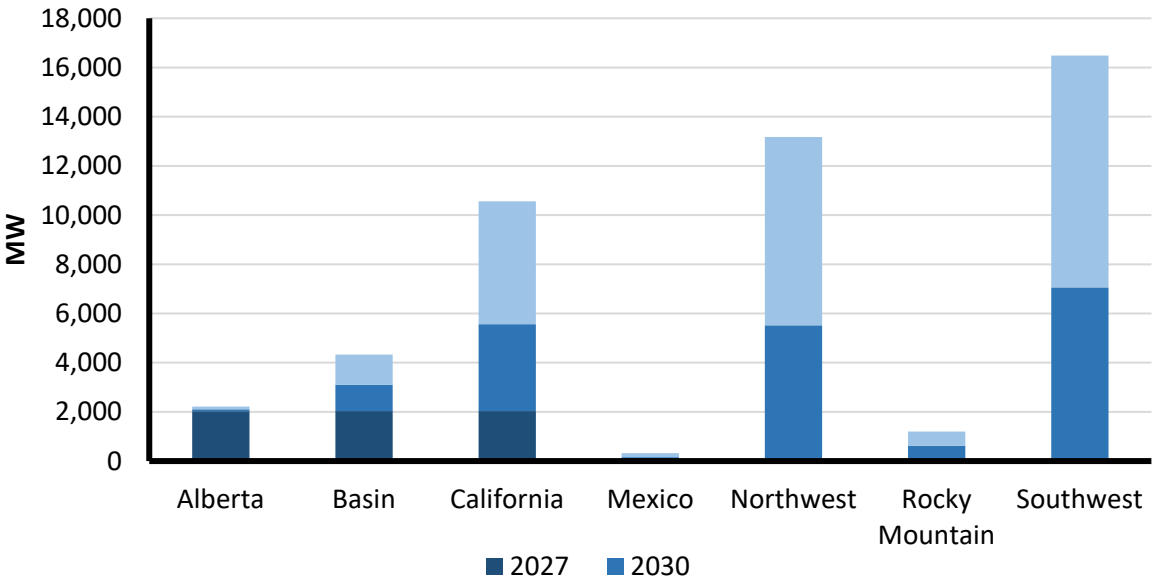


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

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 events²¹ 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.

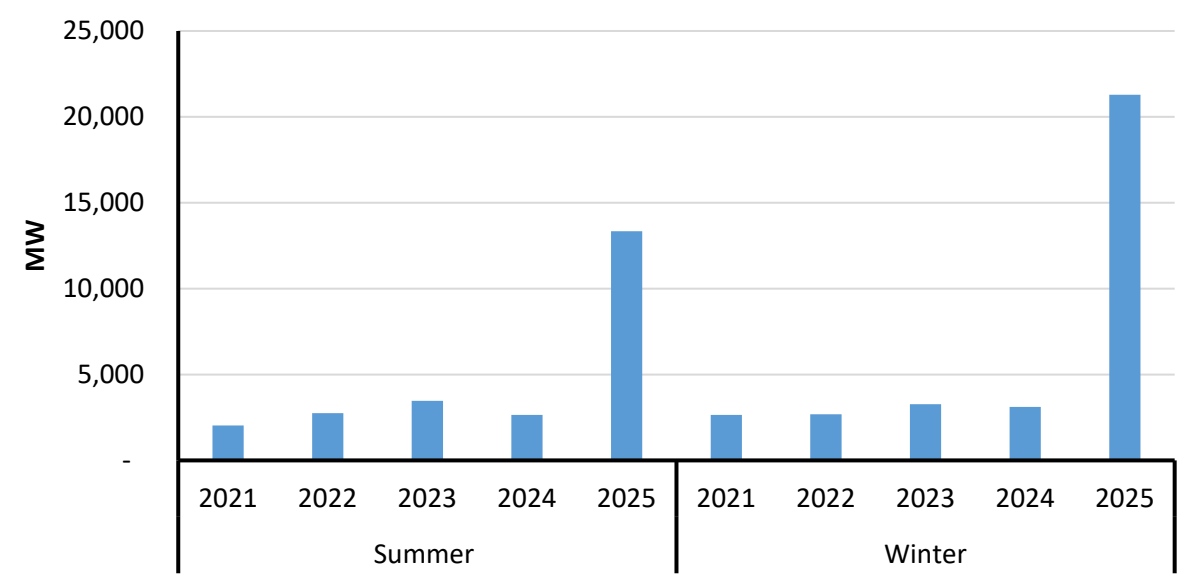


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

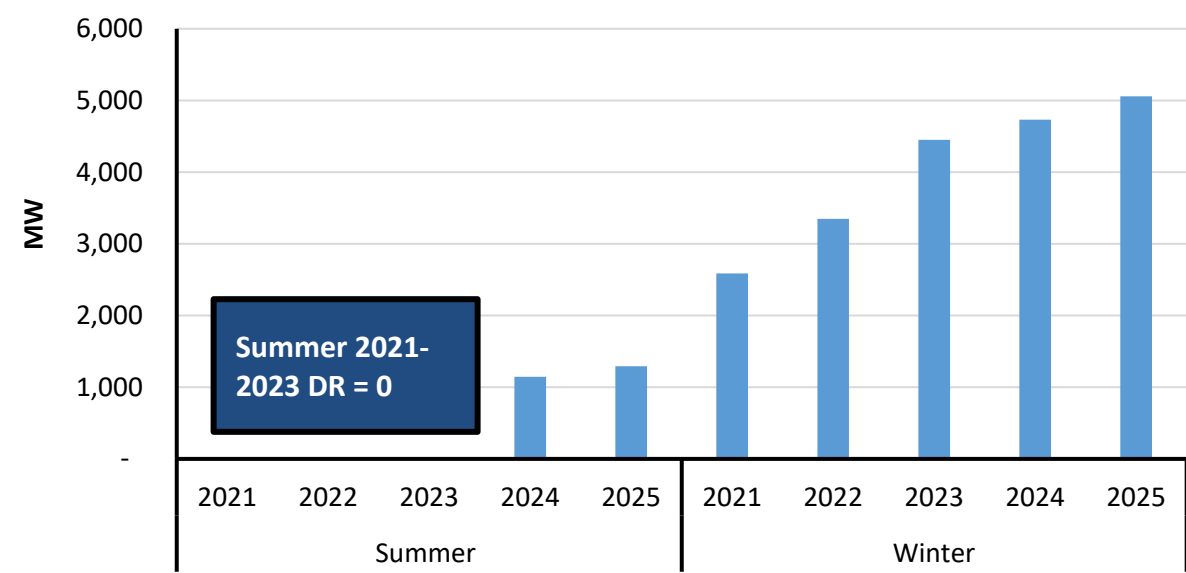


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

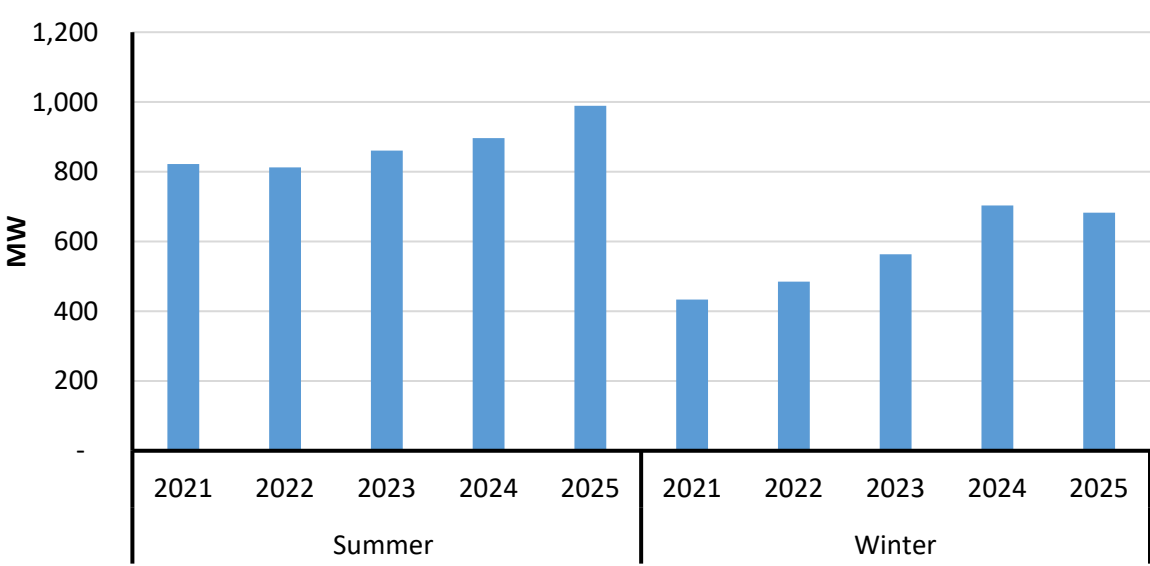


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

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.

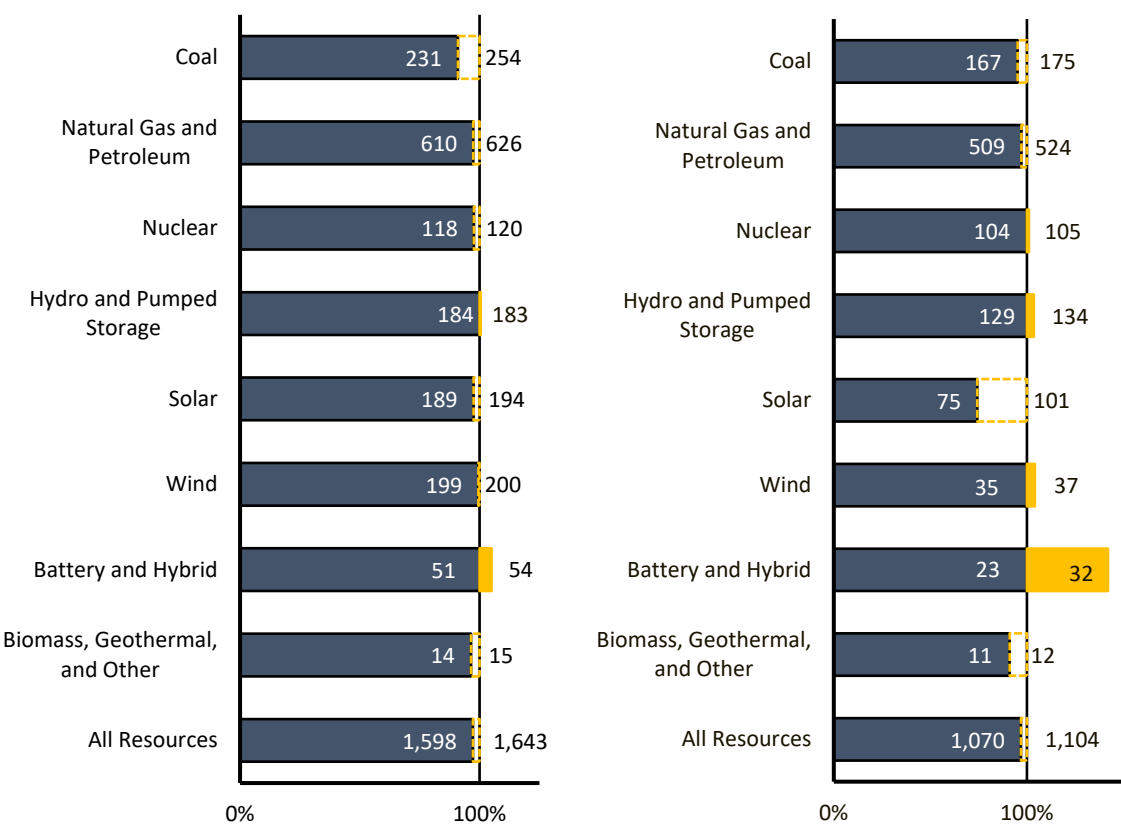


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to 2024 LTRA Projections

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.

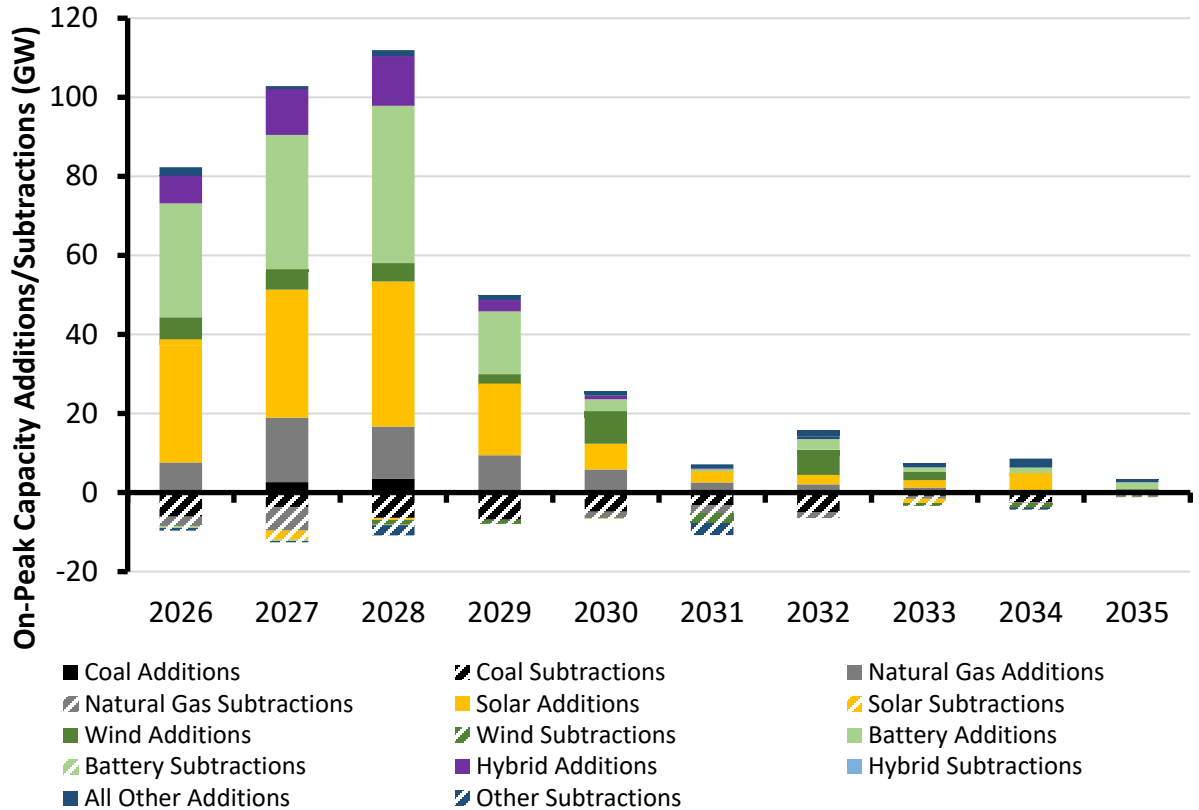


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

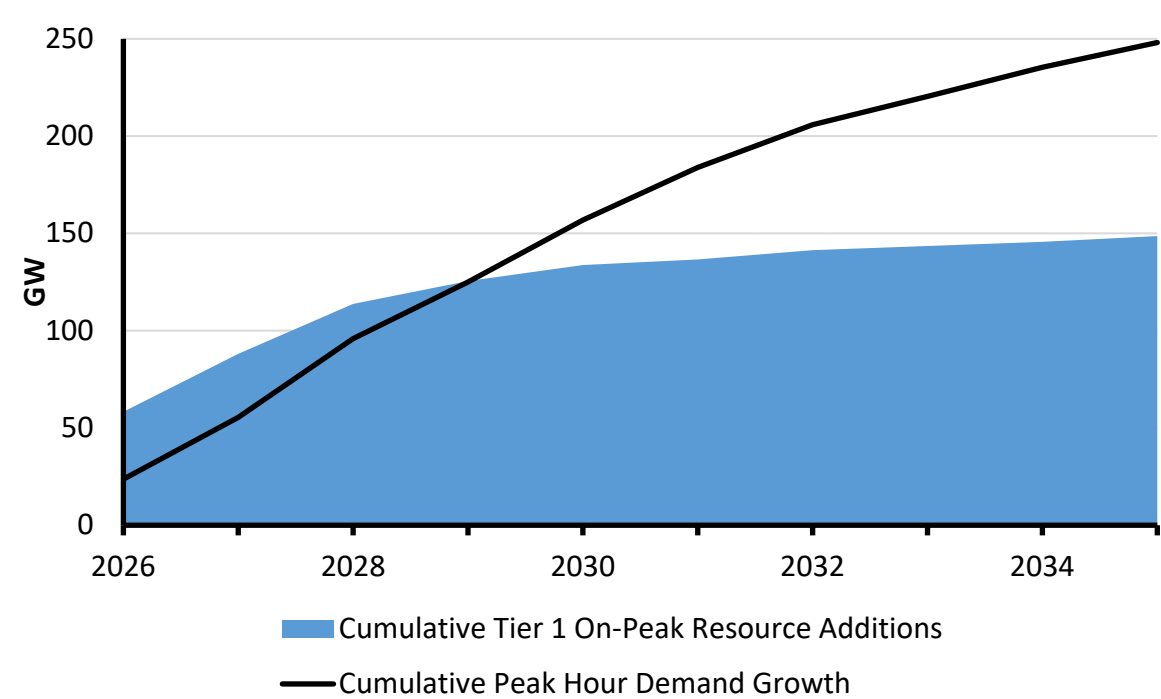


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

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.

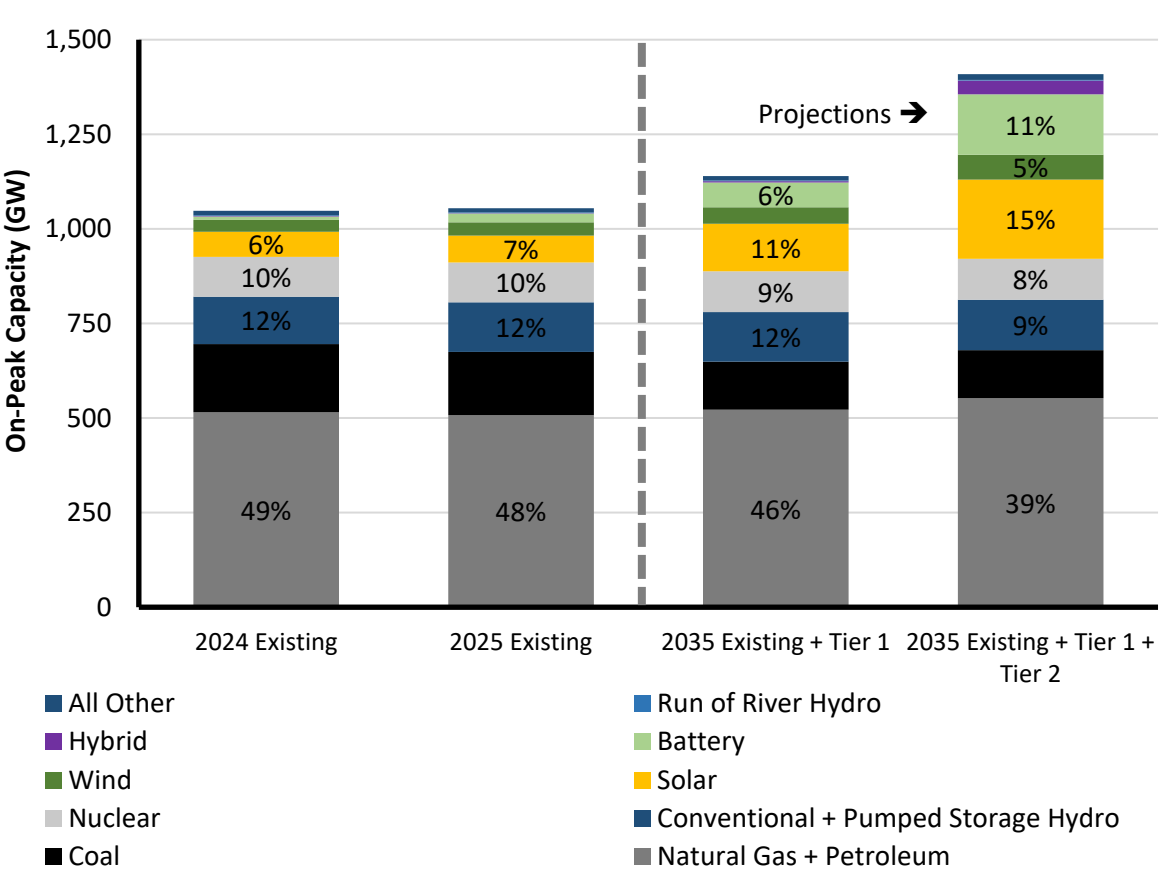


Figure 19: North America On-Peak Capacity Shares by Resource Type

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

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

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.

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.

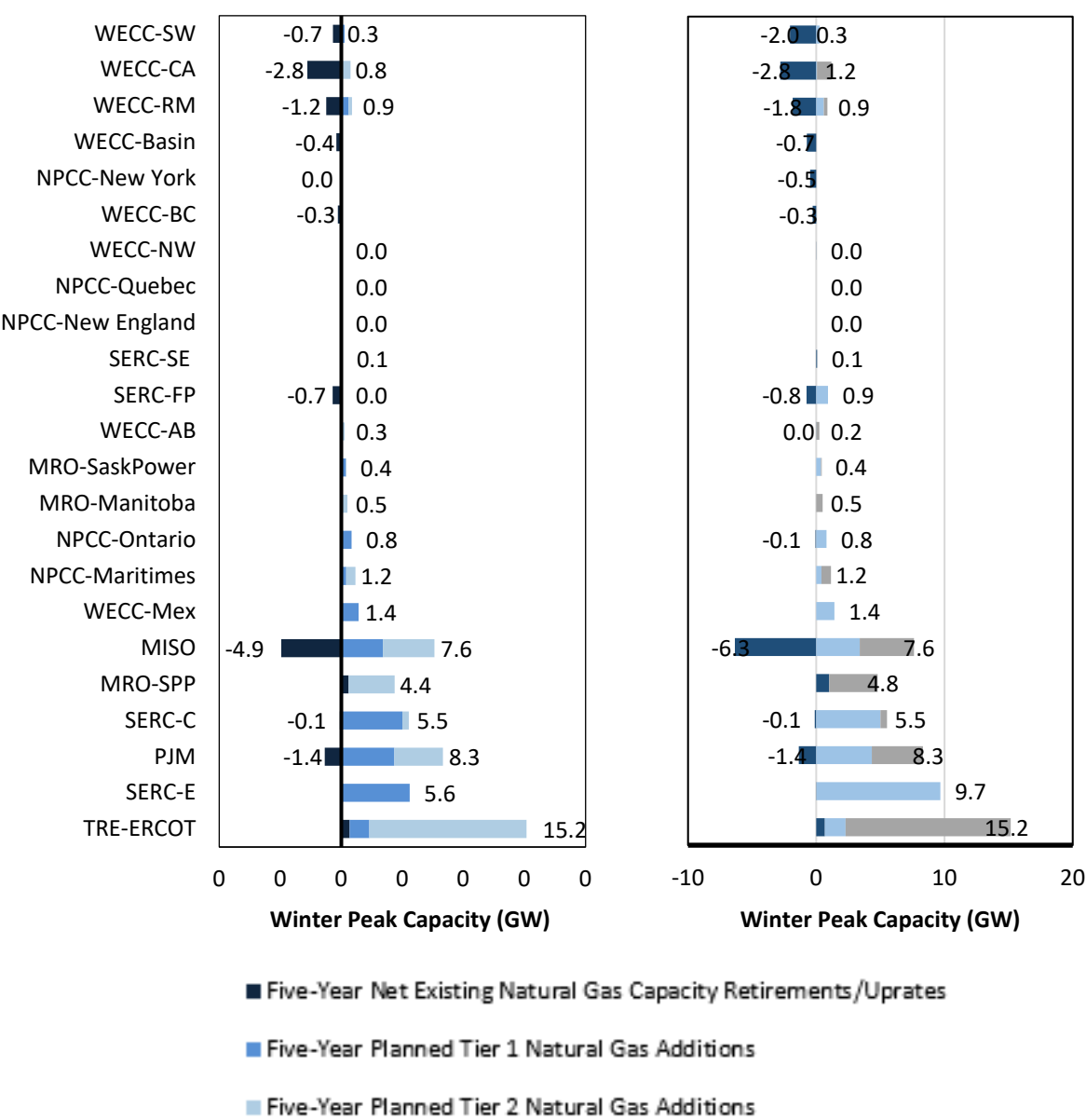


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

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.

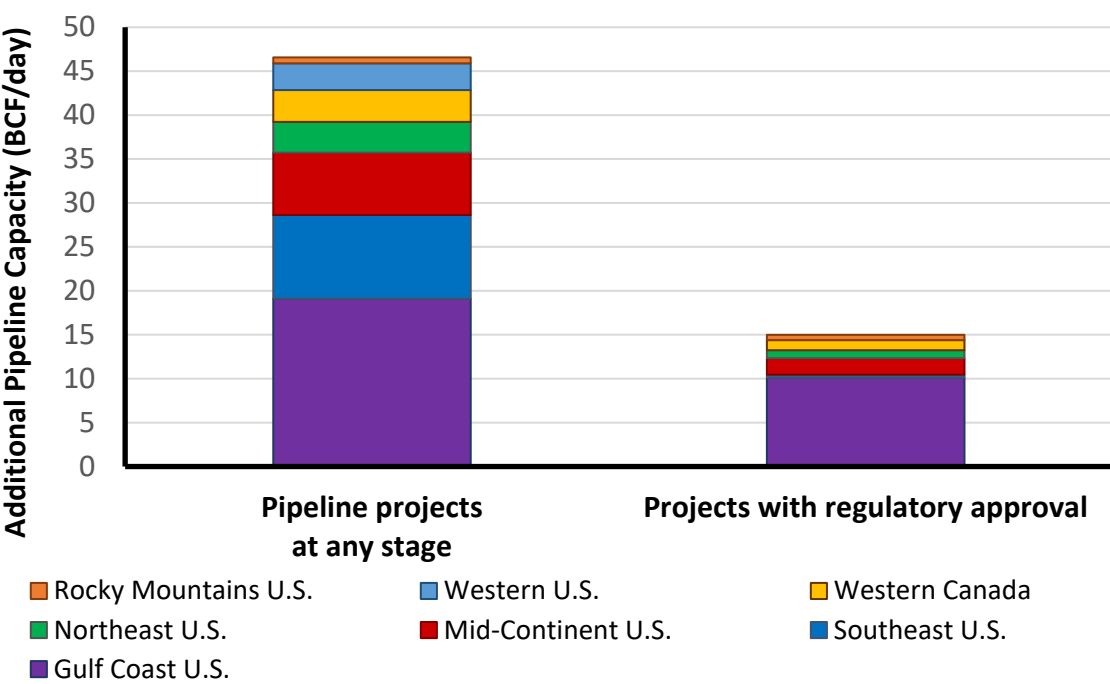


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

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.

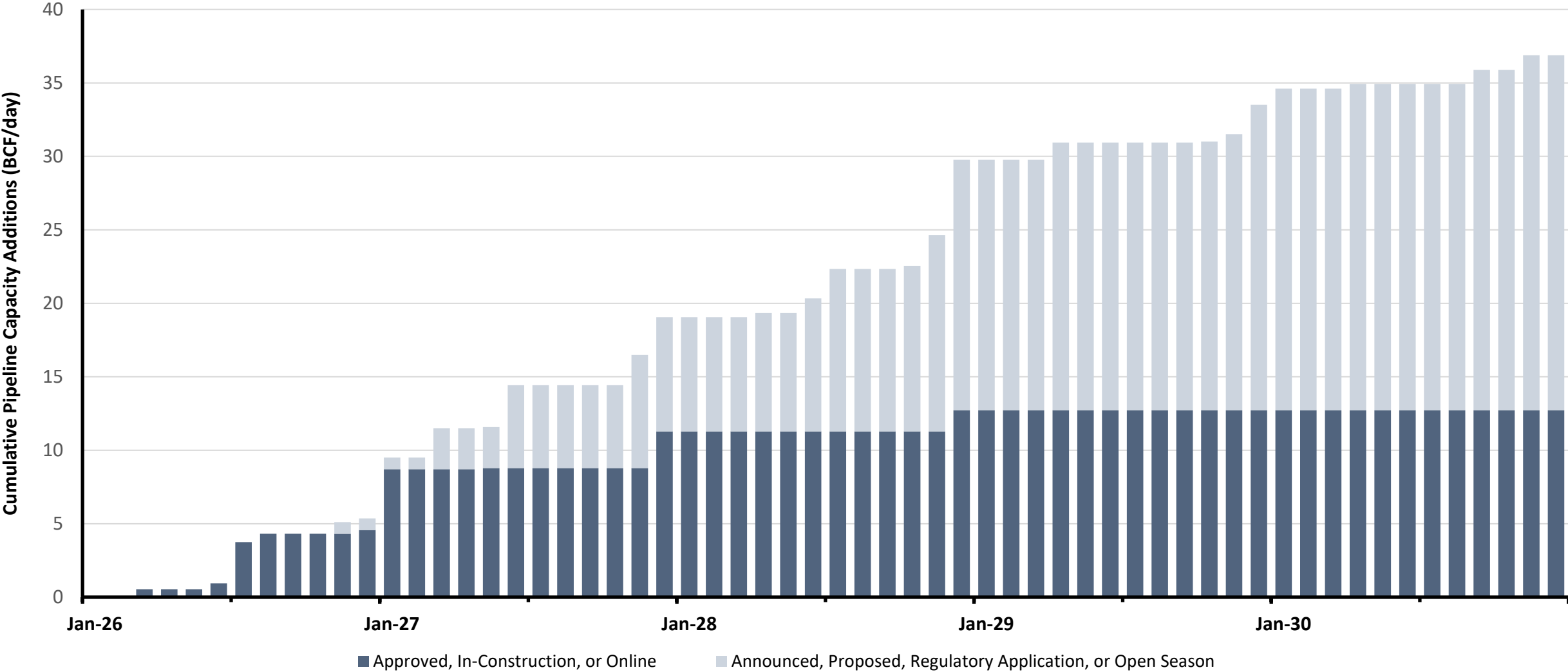


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

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.

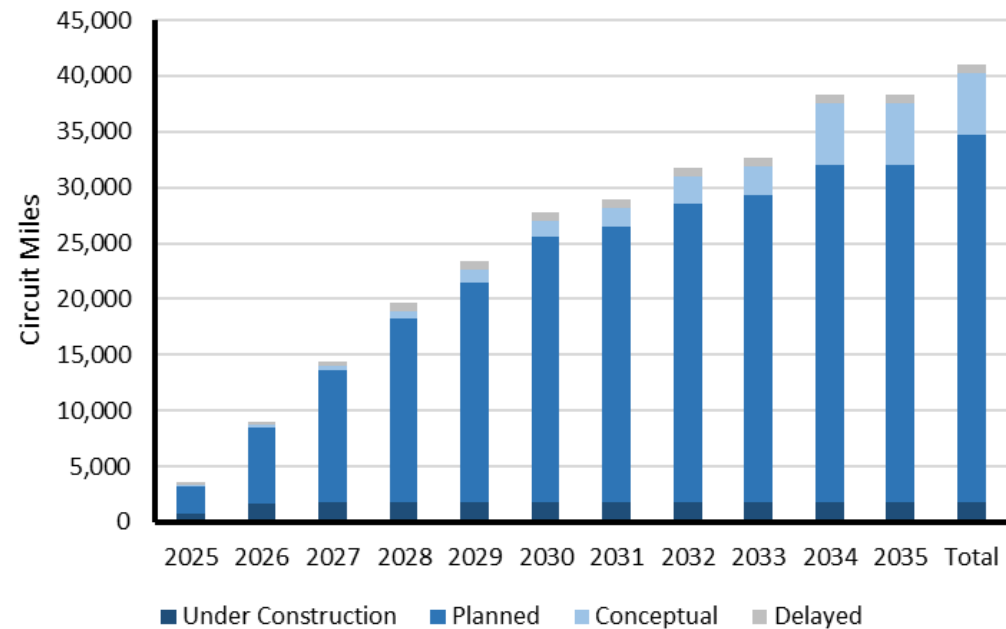


Figure 23: Future Transmission Circuit Miles > 100 kV by Project Status²⁸

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

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.

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.

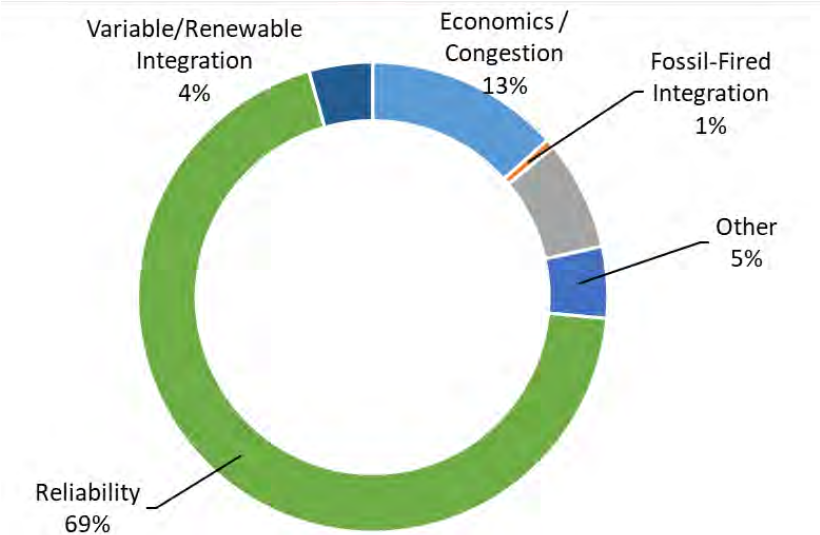


Figure 24: Future Transmission Circuit Miles by Primary Driver

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 Appalachies-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.

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 capability³⁰ 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 TPR³³ but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

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

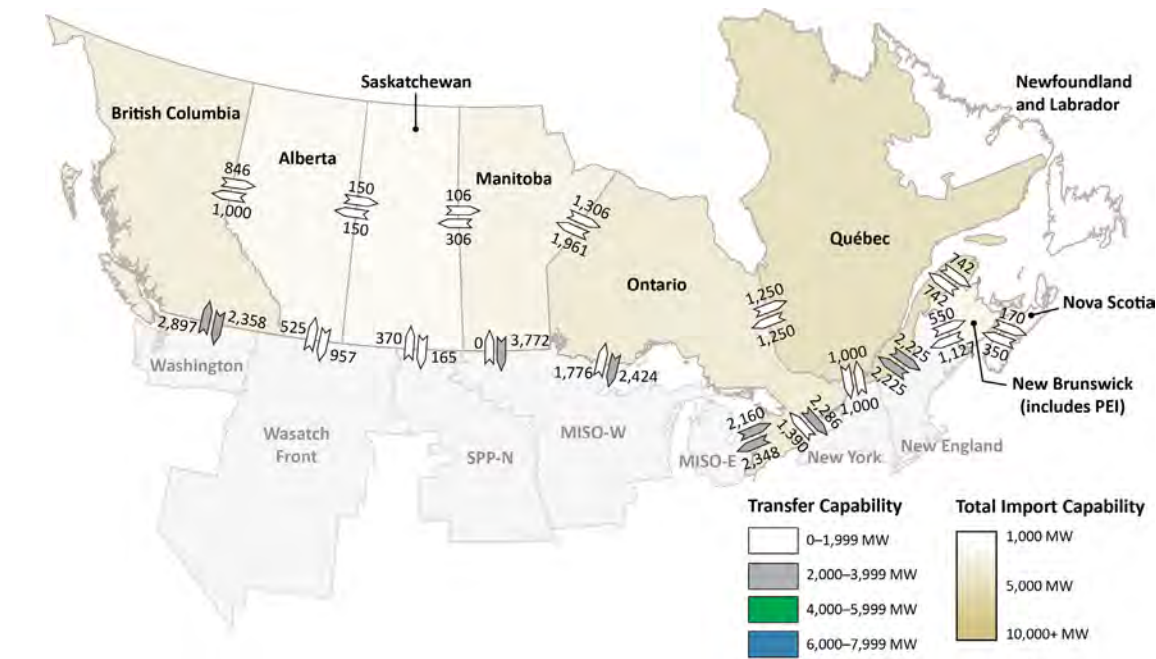


Figure 25: Transfer Capabilities (Summer)

customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

³² NERC [filing](#) of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

³³ Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

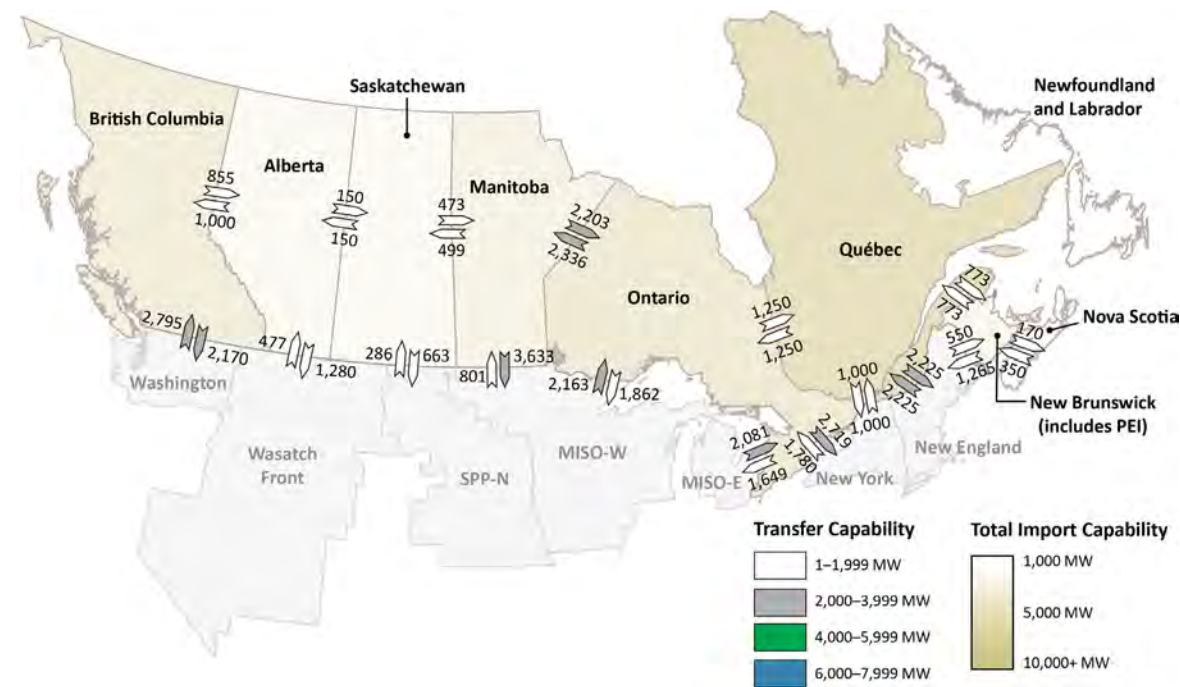


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.³⁴ Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the 2023 *LTRA* using the current transfer capabilities.³⁵ The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC’s role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

³⁴ This study did not incorporate climate change models.

³⁵ The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in 2024 LTRA data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study’s assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province’s vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on 2023 LTRA data. A sensitivity study using more recent forecasts, based on 2024 LTRA data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. [Figure 27](#) shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

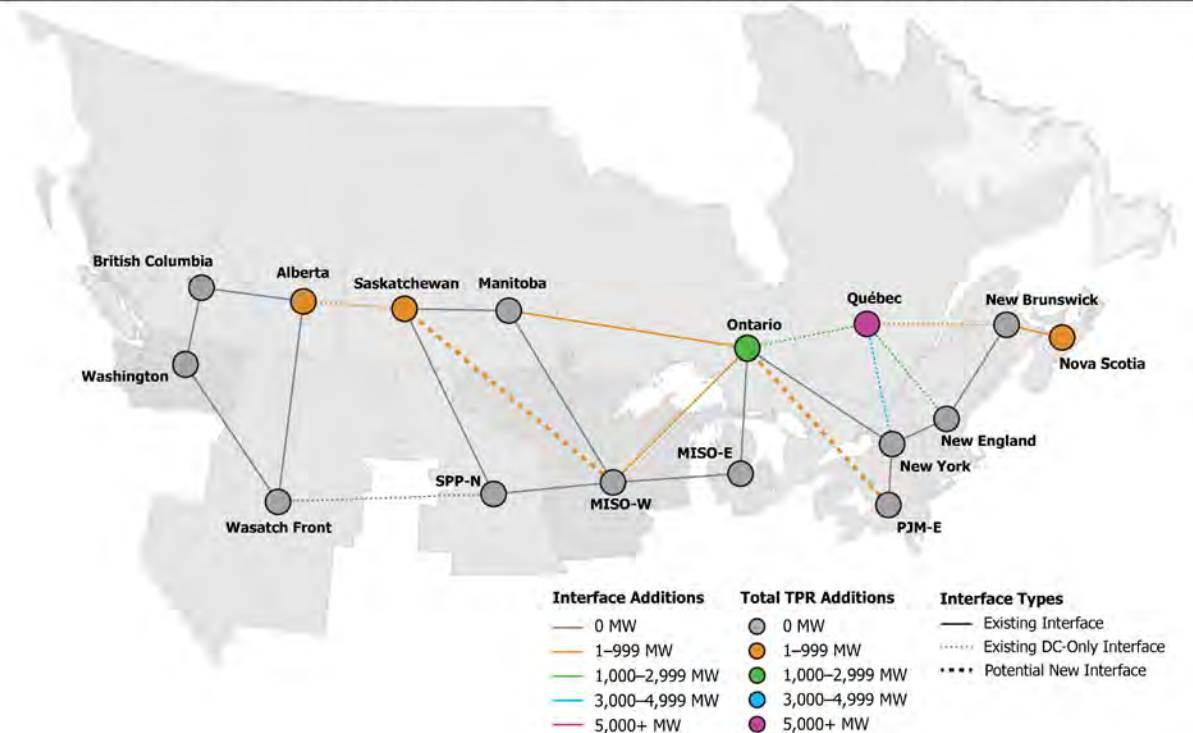
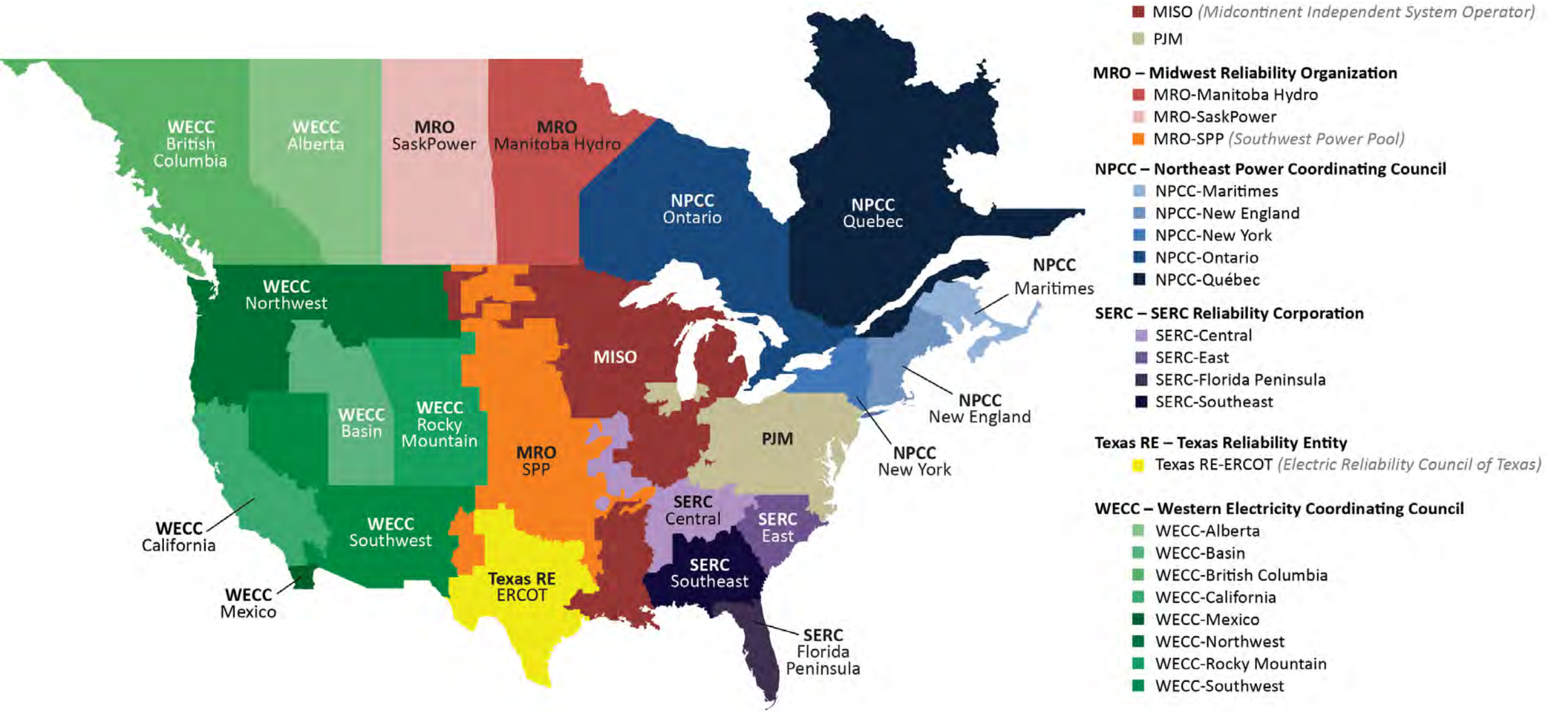


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC’s RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



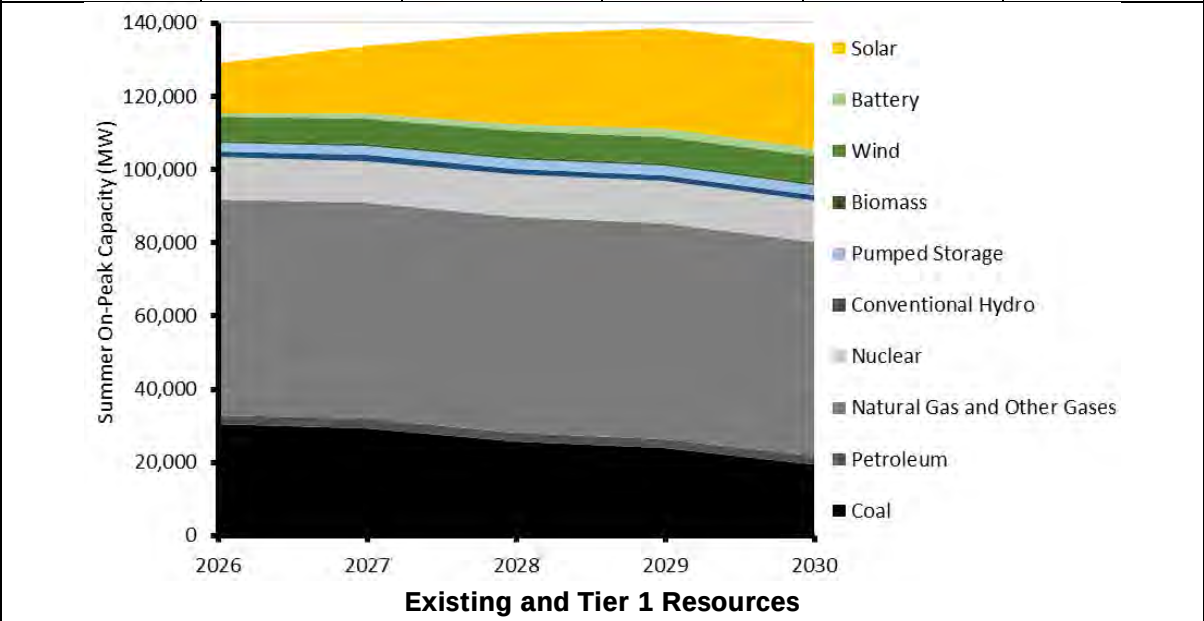
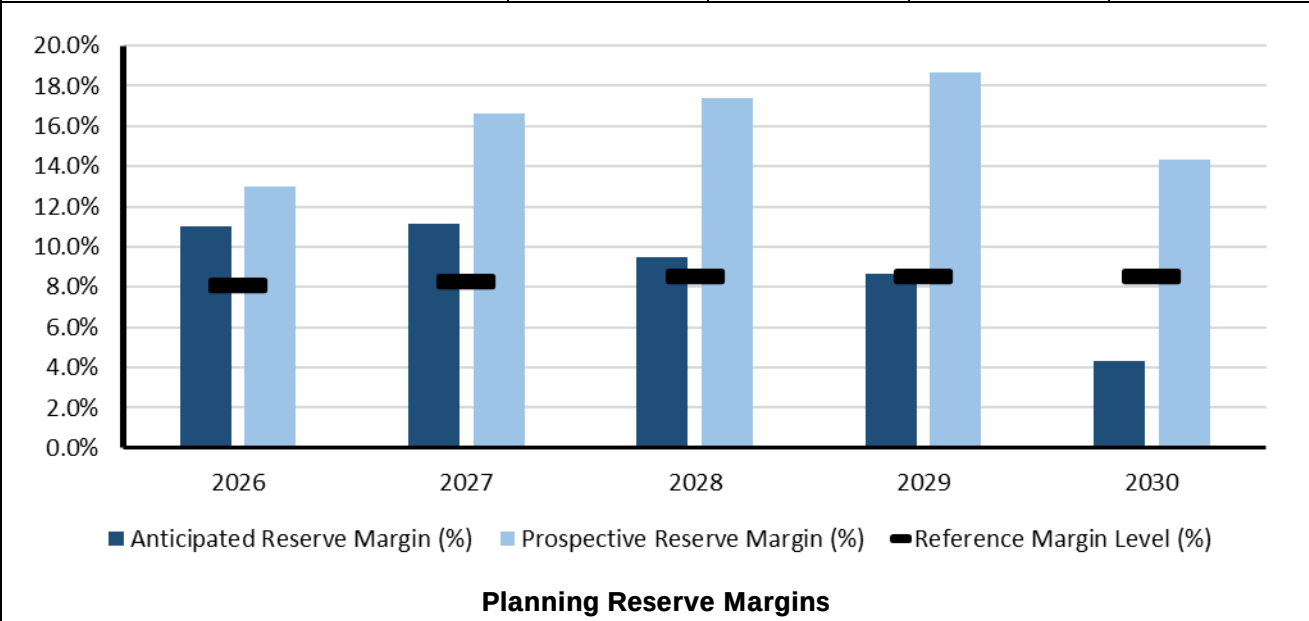


MISO

The Midcontinent Independent System Operator, Inc. ([MISO](#)) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world’s largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO’s footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



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.

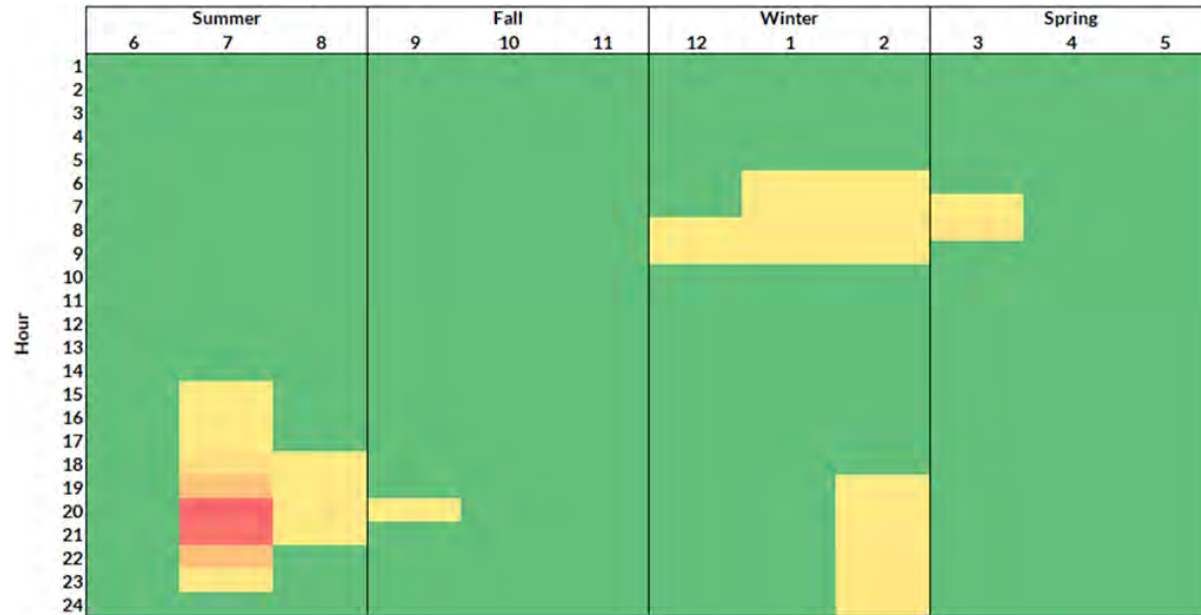
The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- 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.

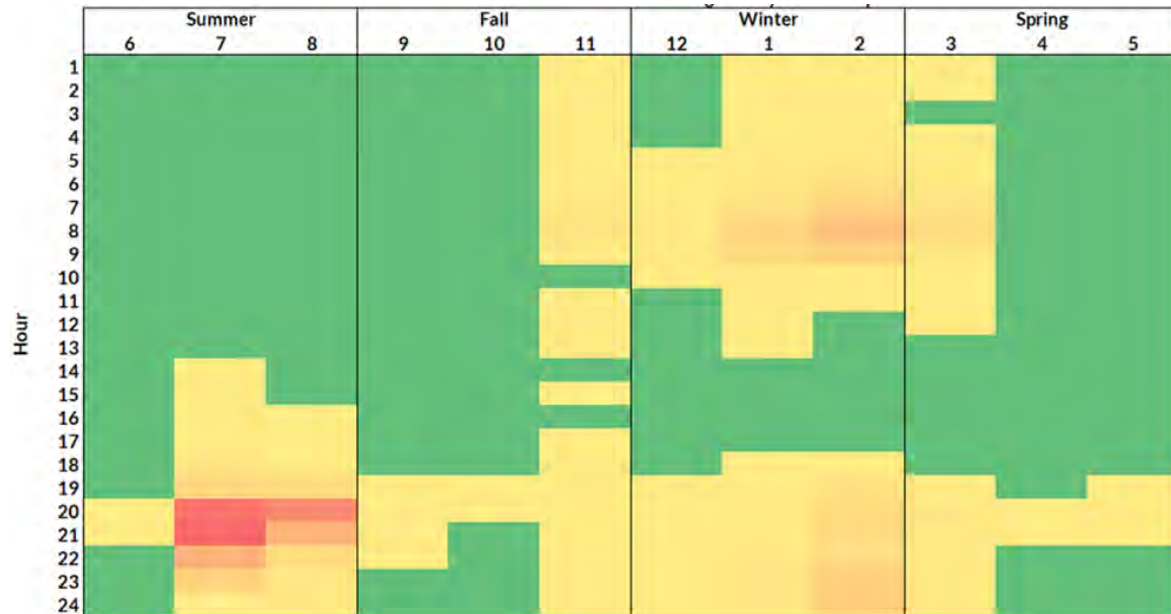
Base-Case Summary of Results			
	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

*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.

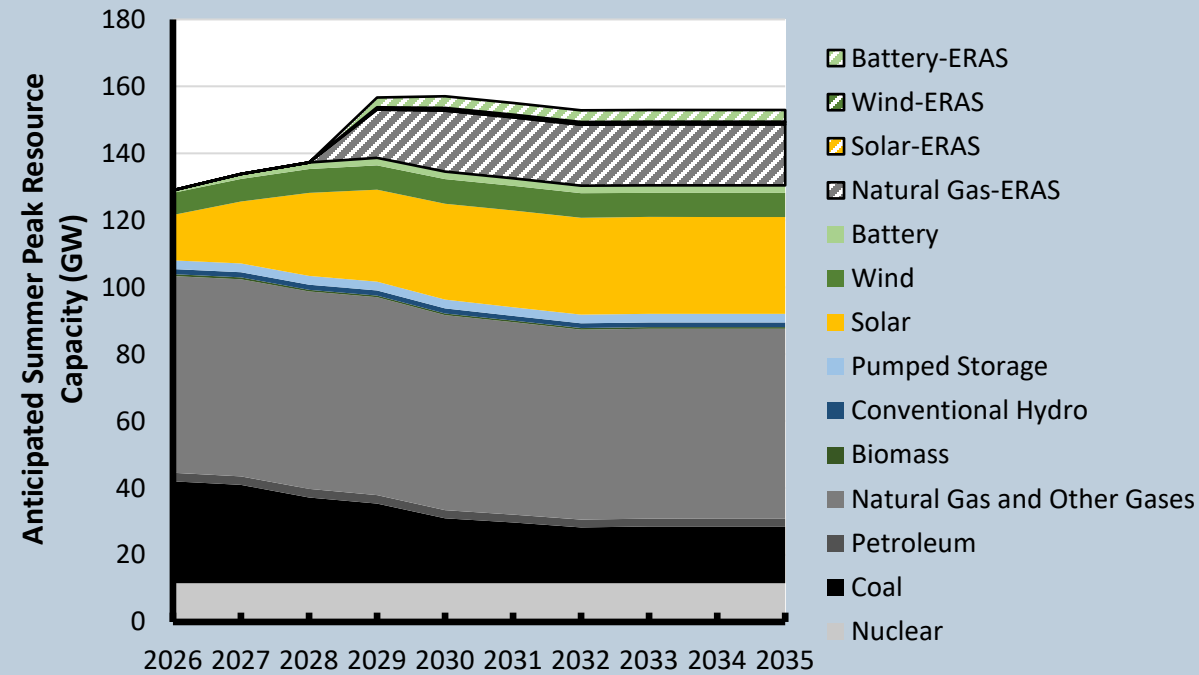
MISO’s accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA 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.

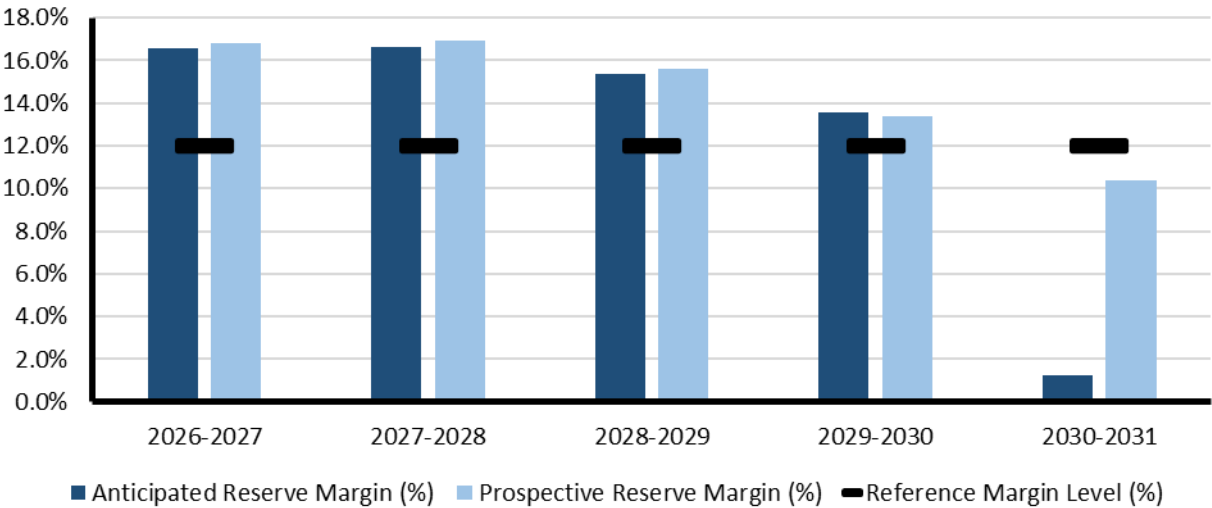


MRO-Manitoba Hydro

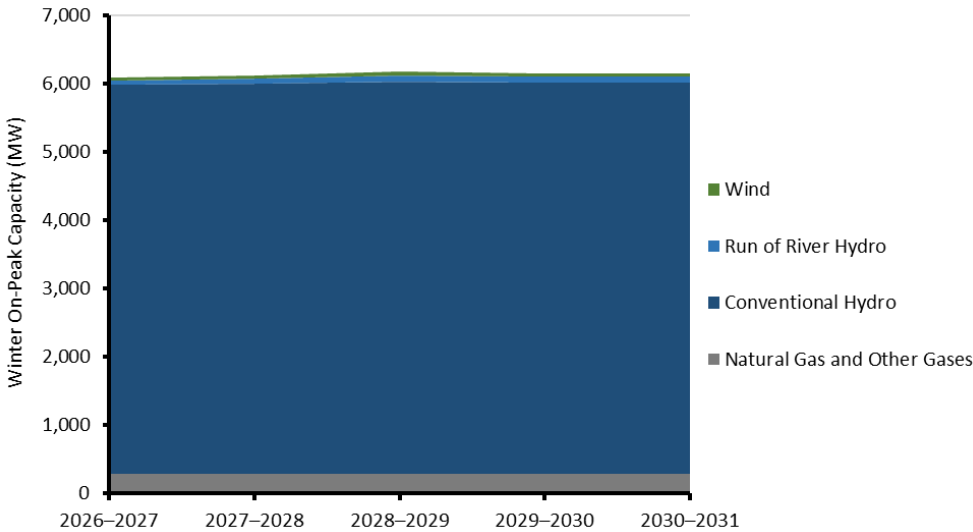
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in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

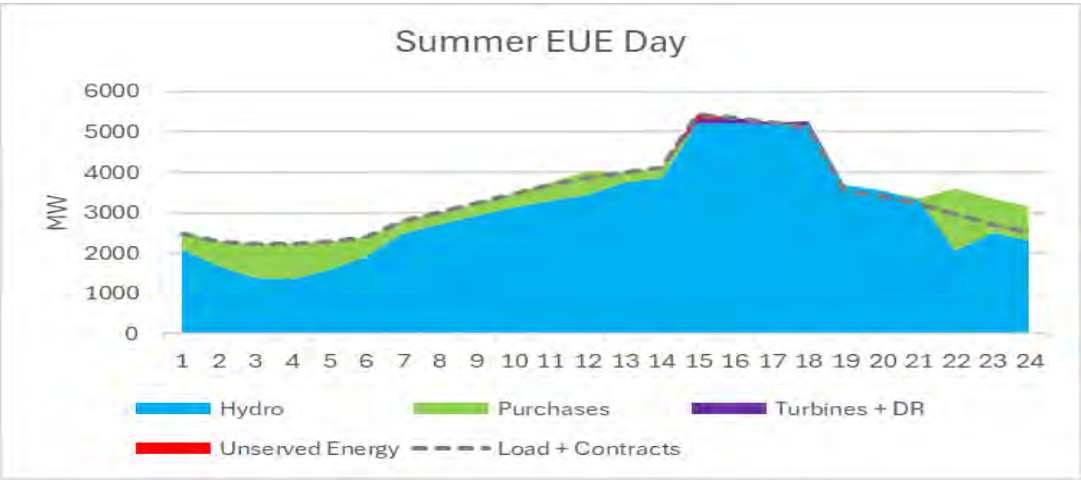
There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow 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.

2029 EUE Heat Map



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.

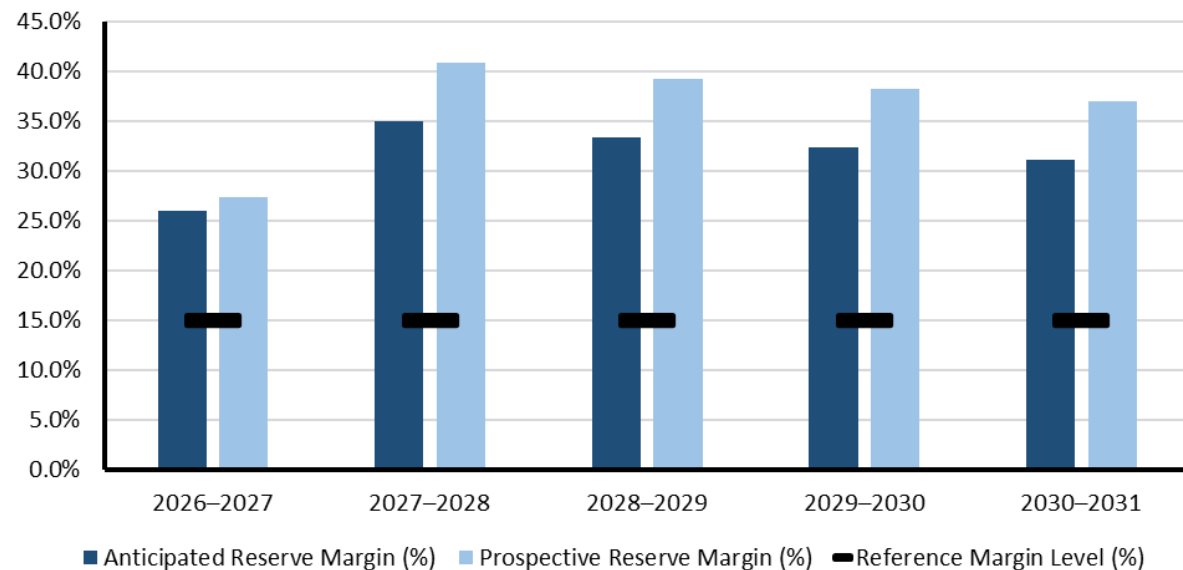


MRO-SaskPower

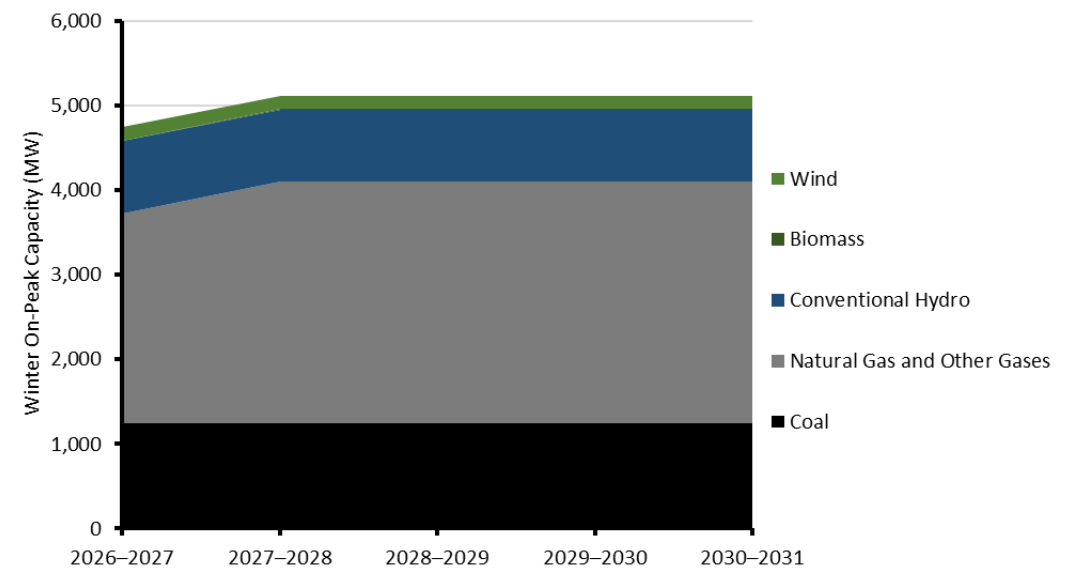
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator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

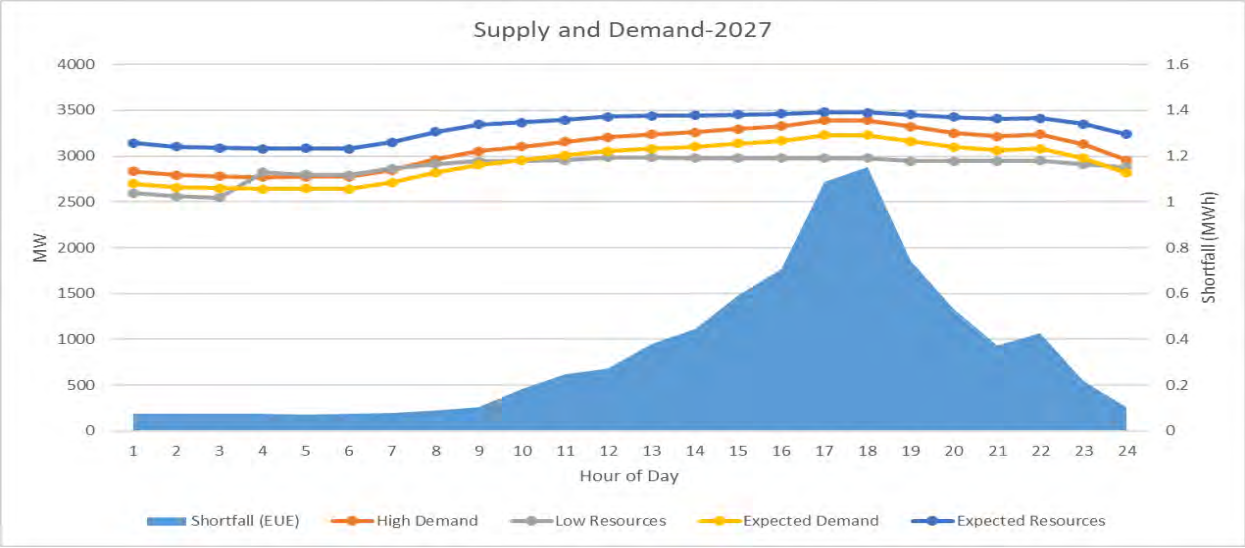
The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

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.

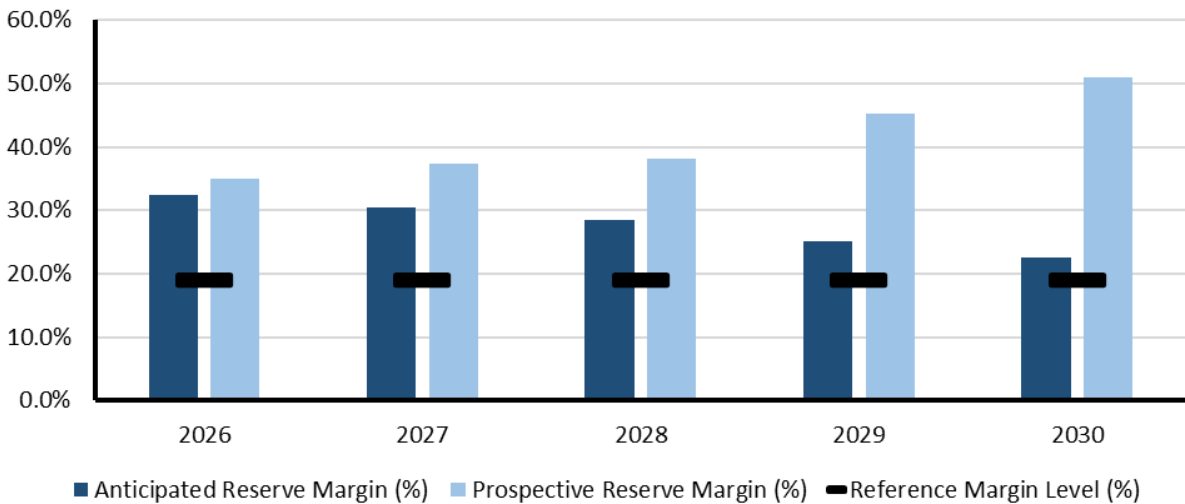


MRO-SPP

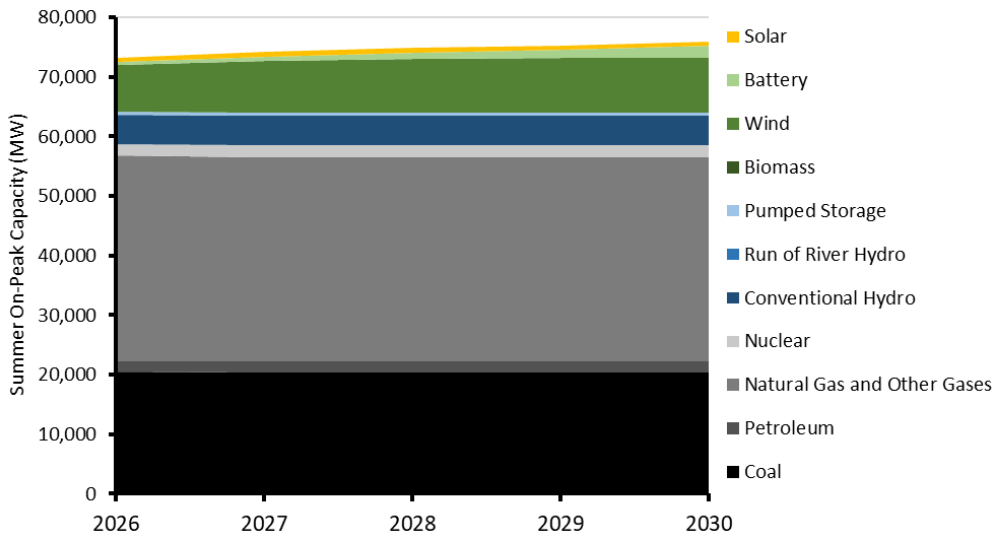
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the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

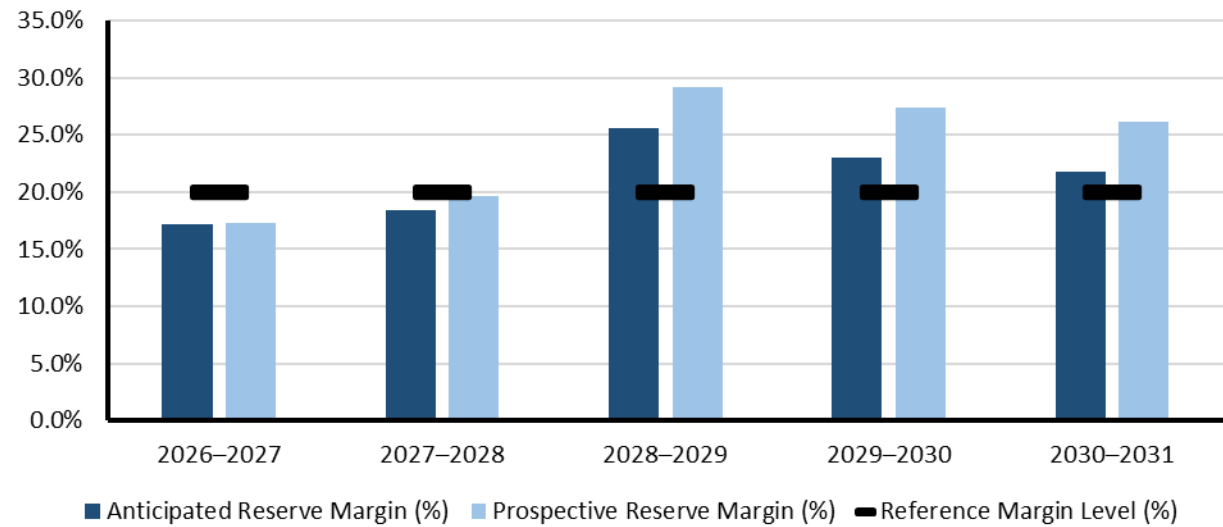


NPCC-Maritimes

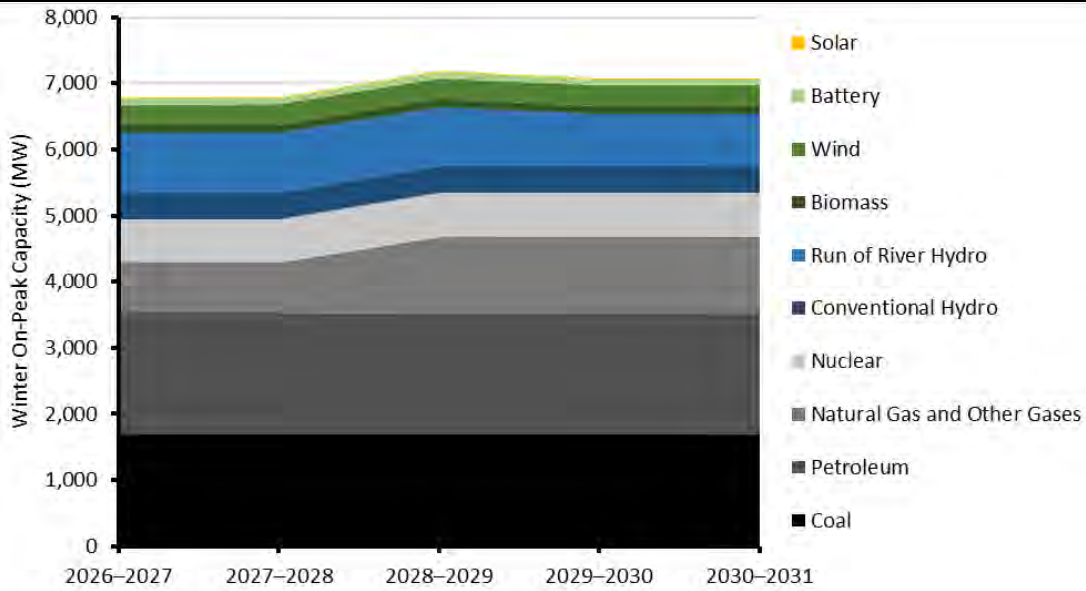
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly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

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

(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.

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.



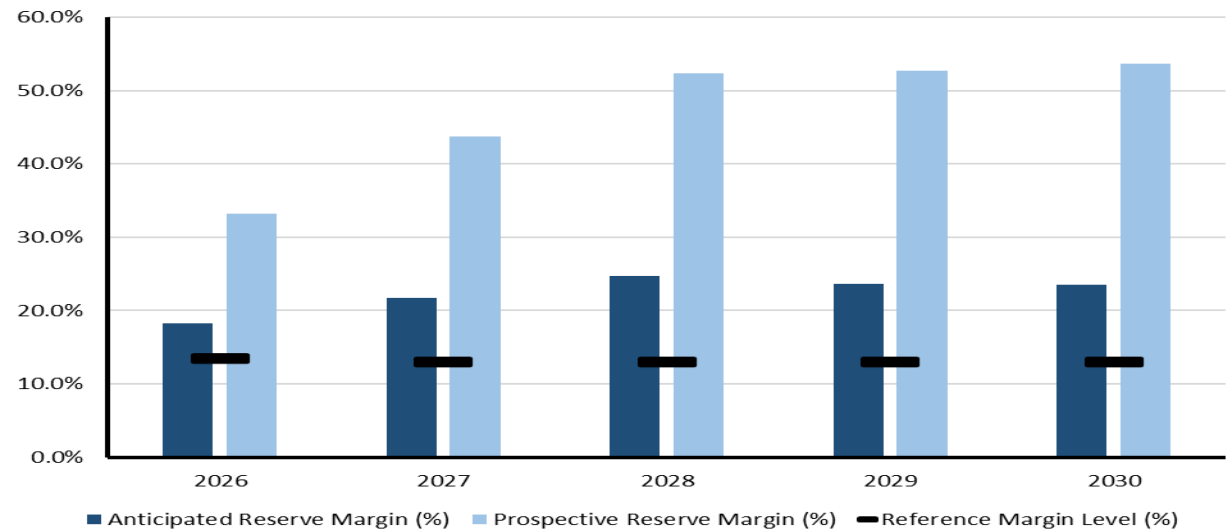
NPCC-New England

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.

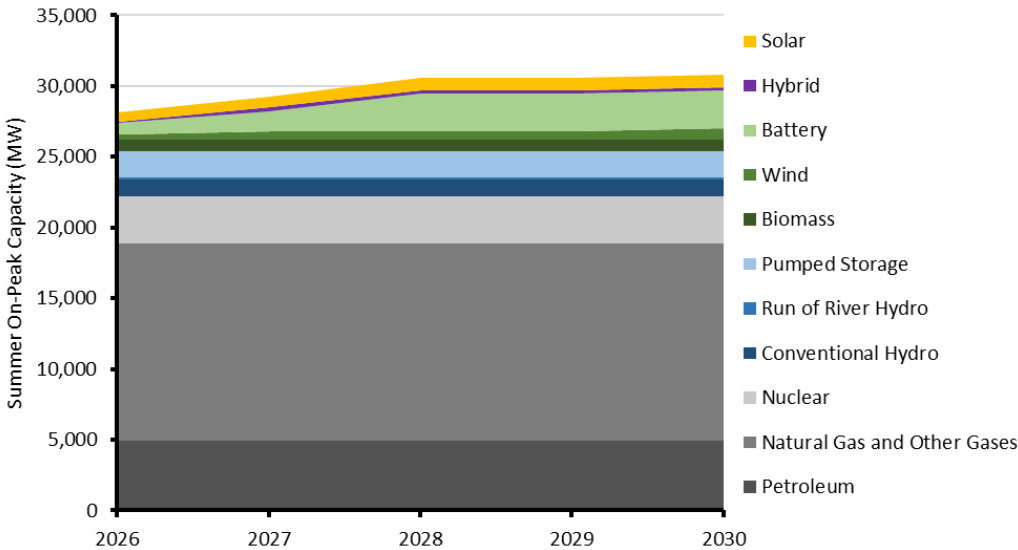
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

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.

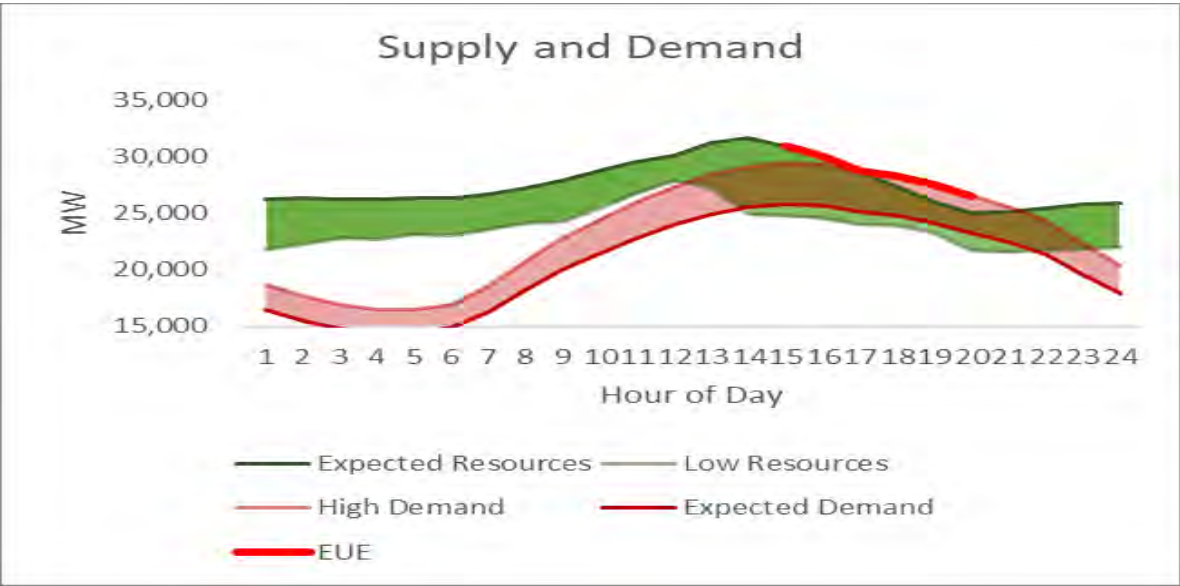
NPCC New England Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

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](#)

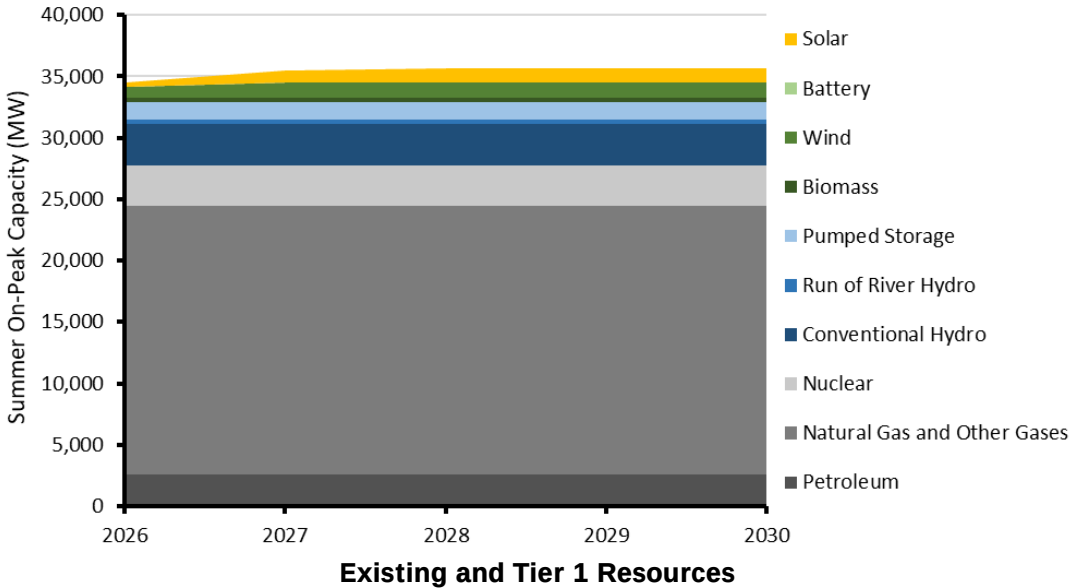
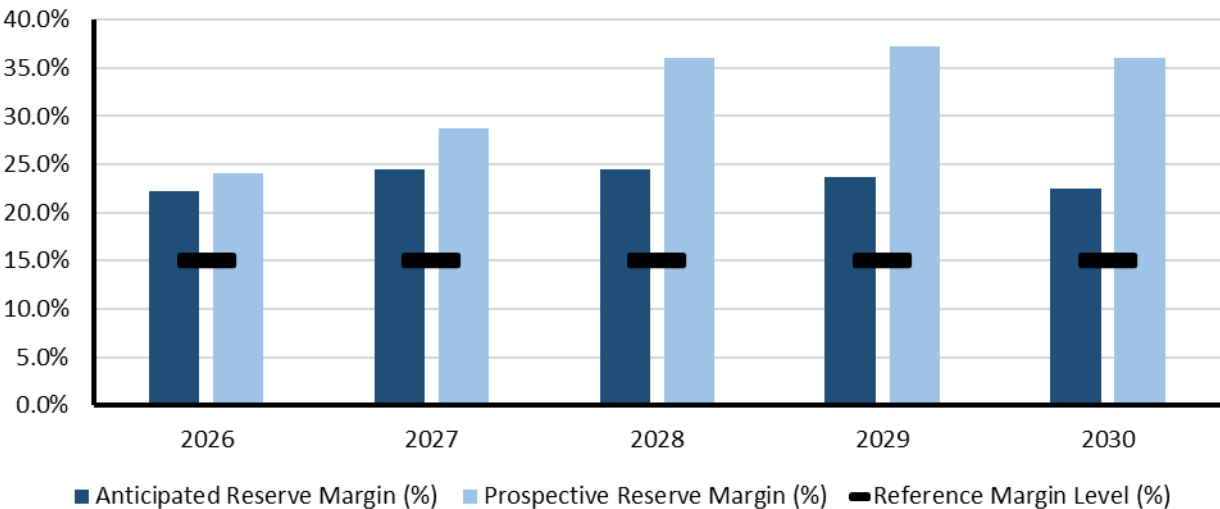


NPCC-New York

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%



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>

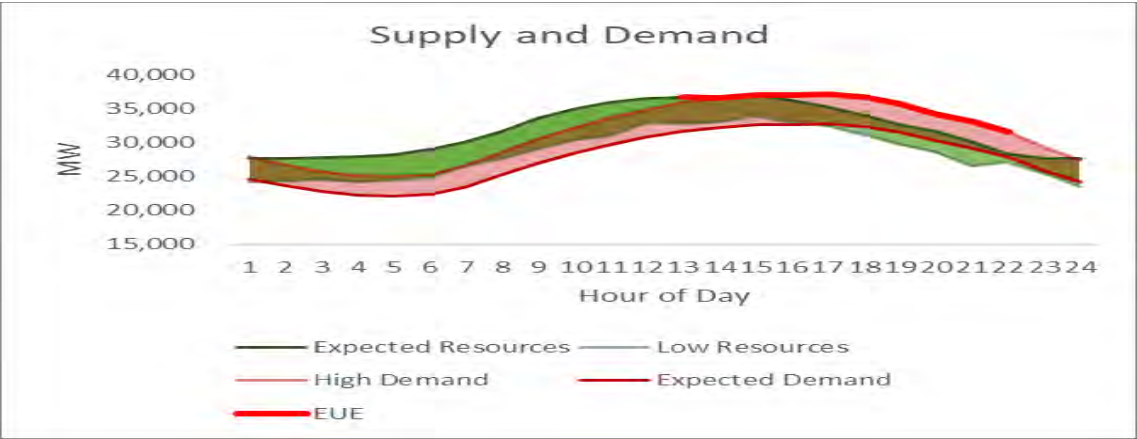
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

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%	0%	1%	7%	24%	25%	7%	3%	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 process⁴¹ 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.

⁴¹ <https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx>

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.

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 analysis⁴⁴ 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 report⁴⁵ 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.p](https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf)
df; Solutions Solicitation: <https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf>

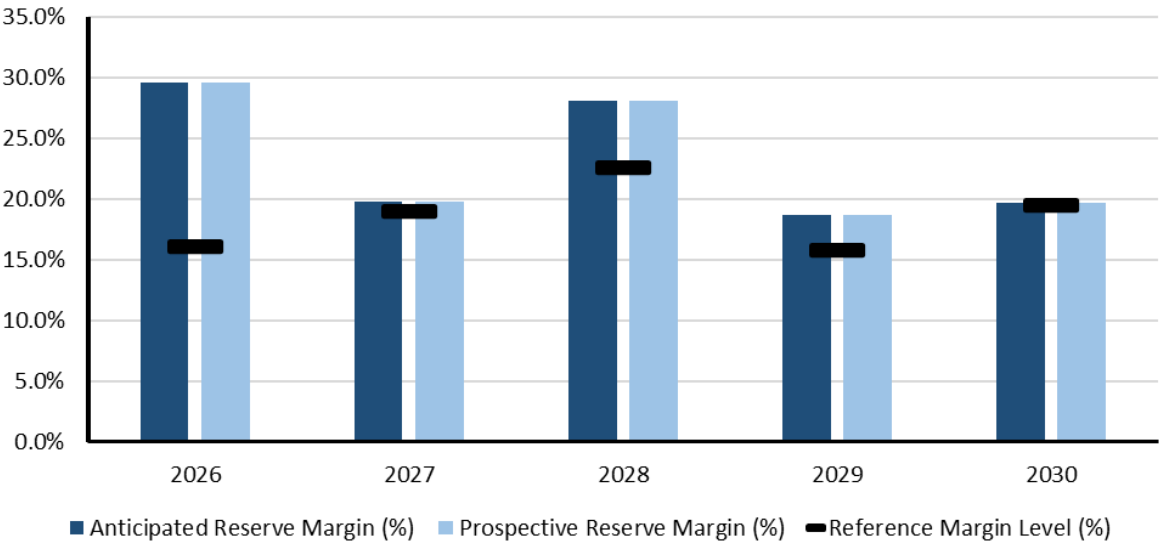


NPCC-Ontario

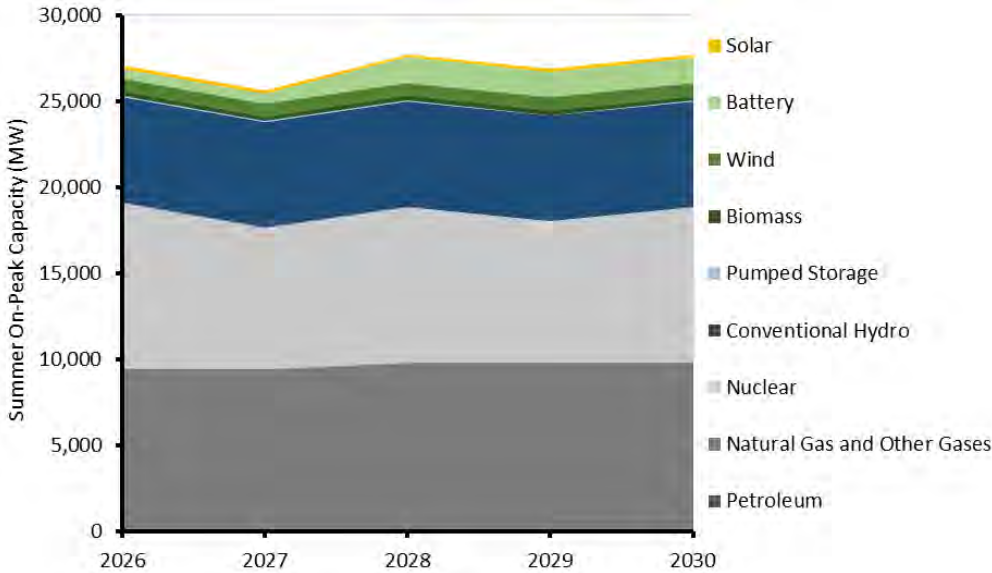
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for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

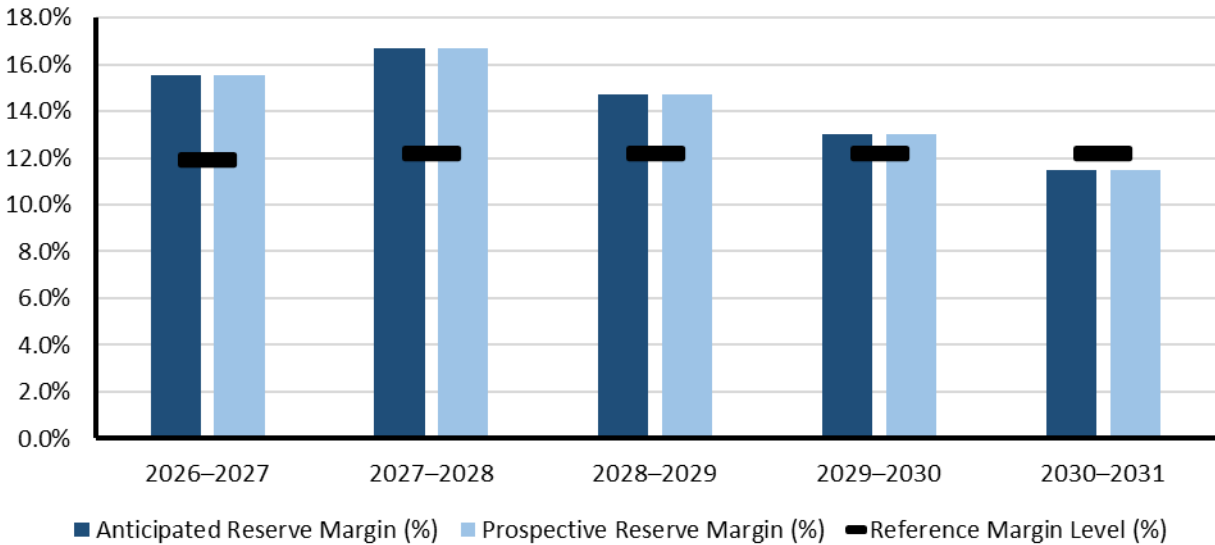


NPCC-Québec

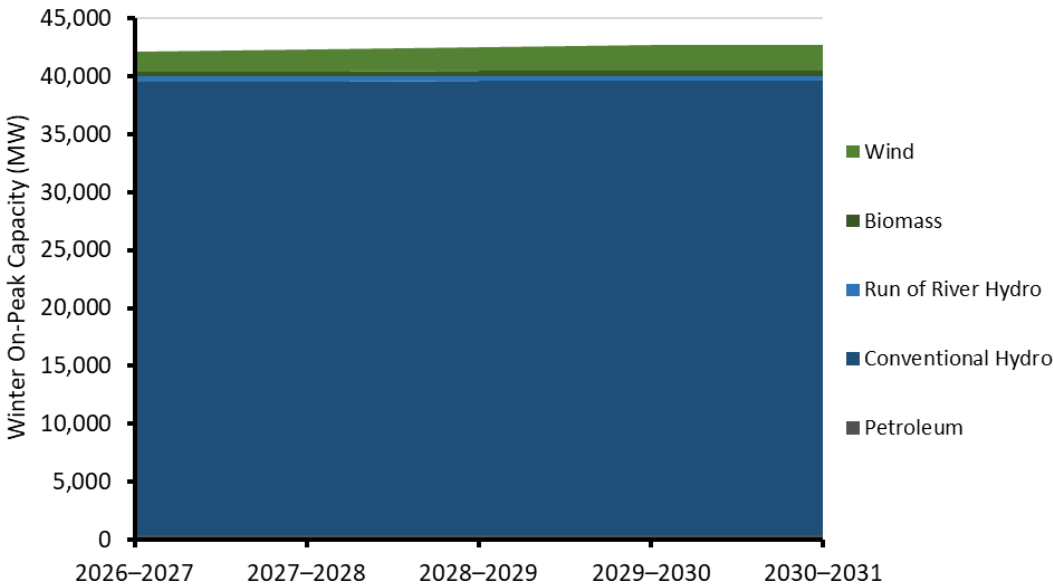
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the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

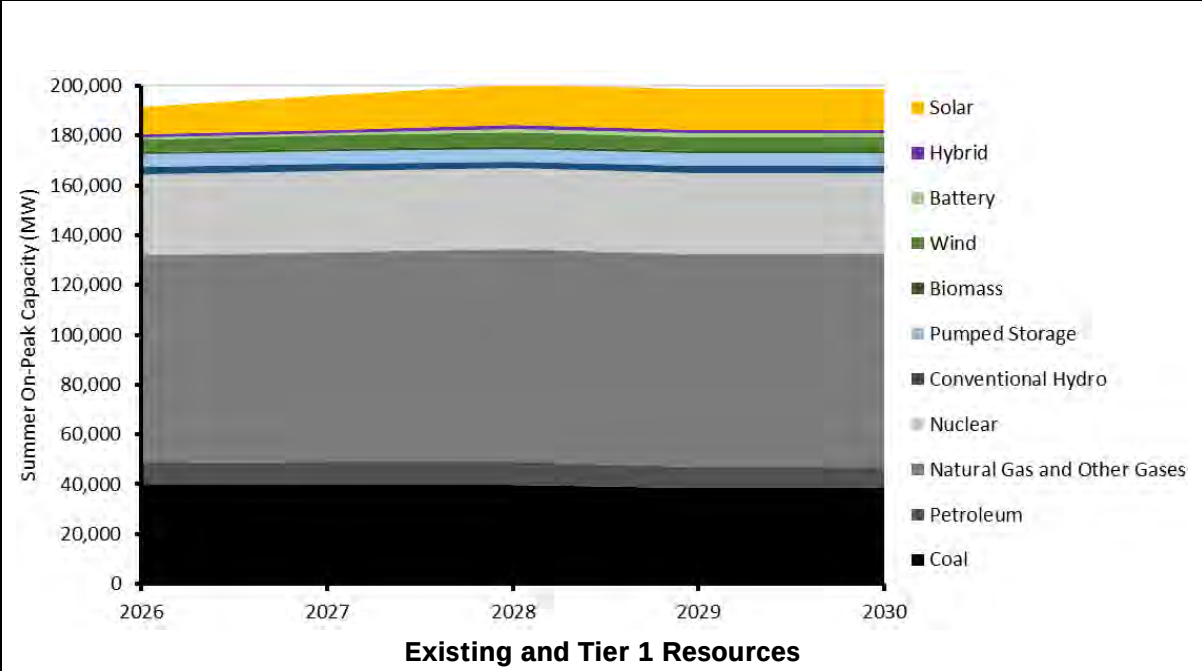
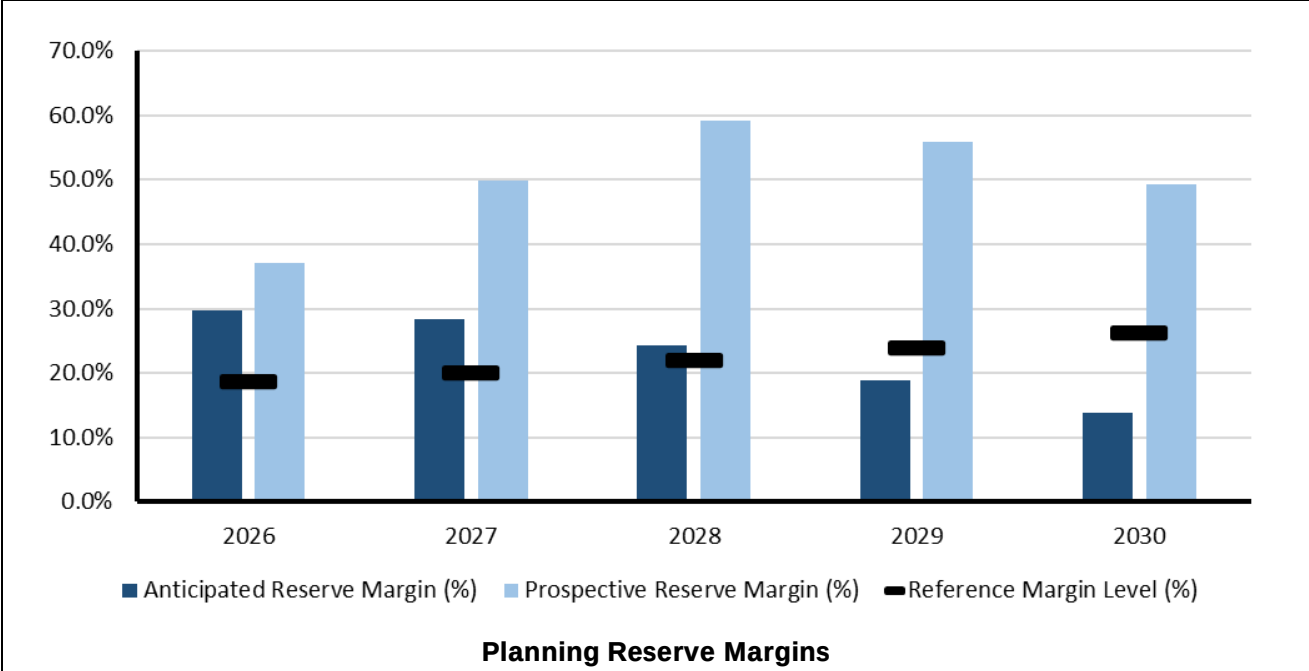


PJM

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%



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 2024 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.

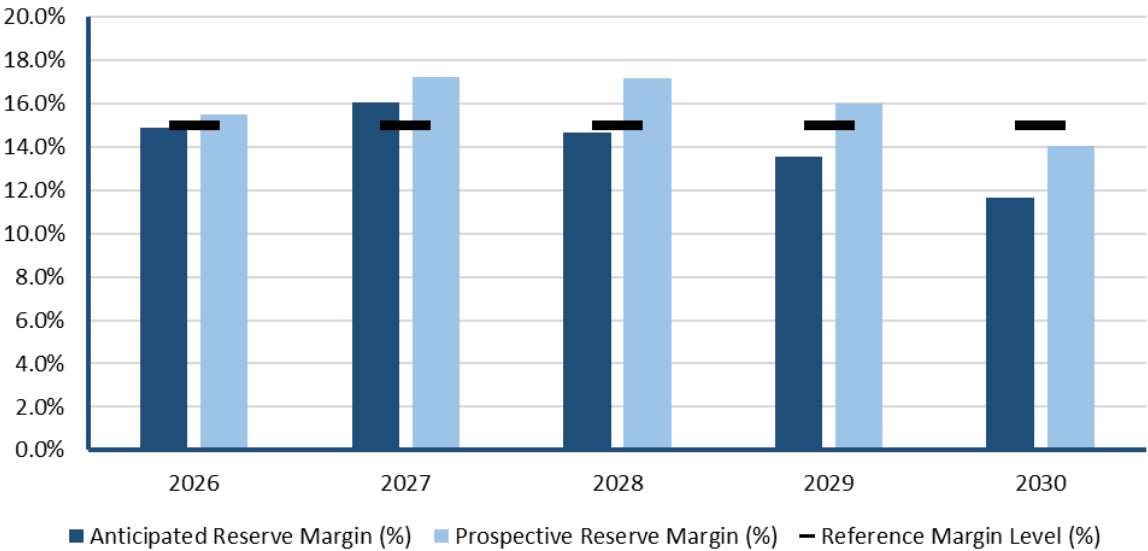


SERC-Central

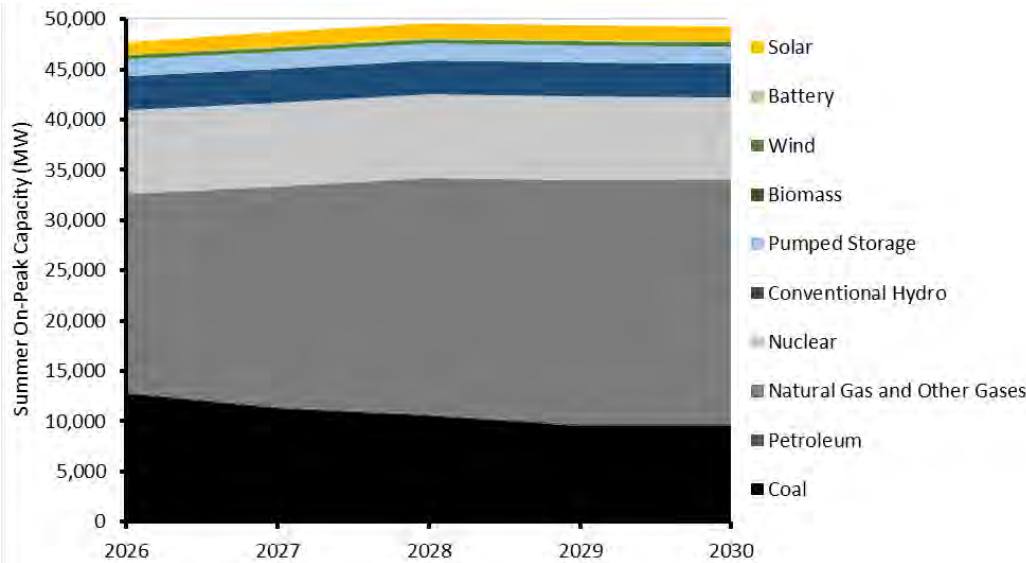
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of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

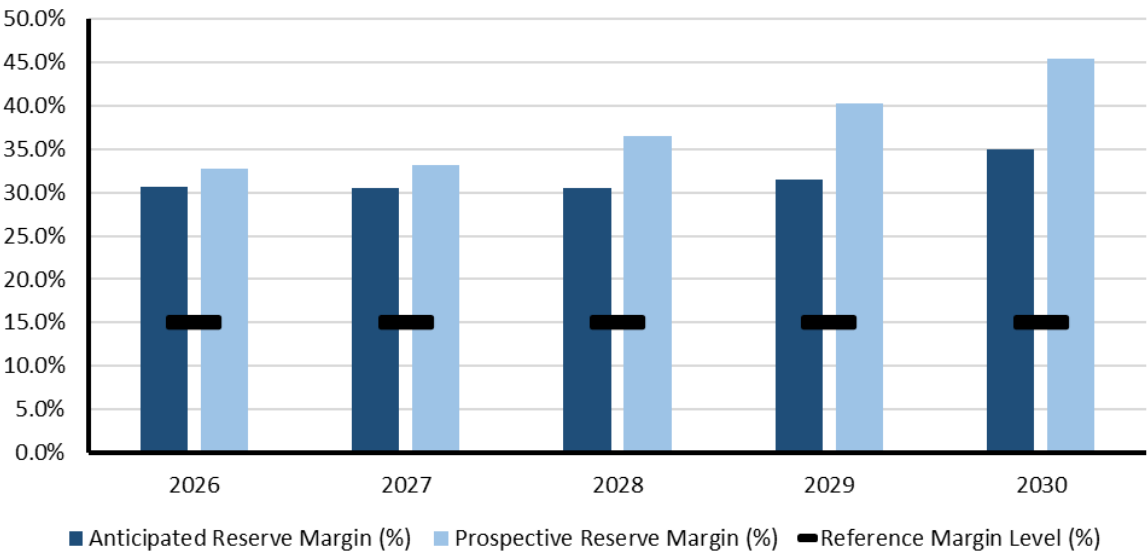


SERC-East

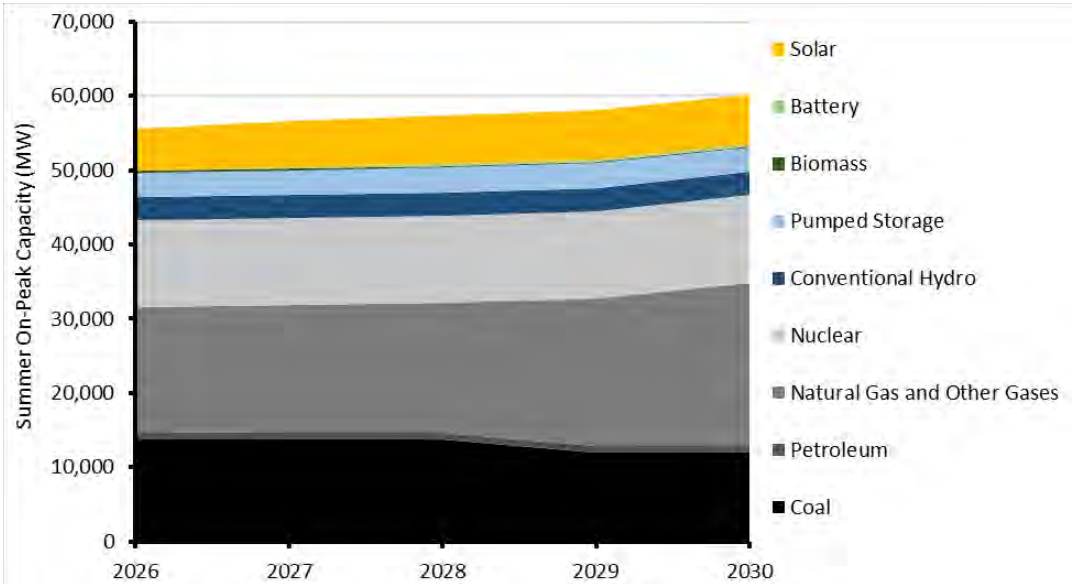
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible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

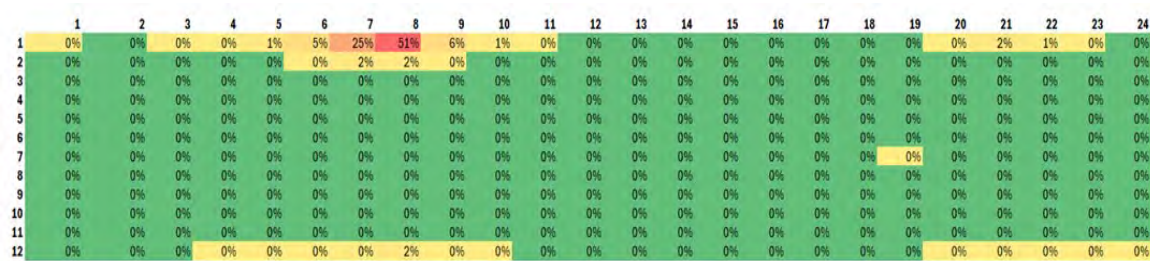
Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. 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

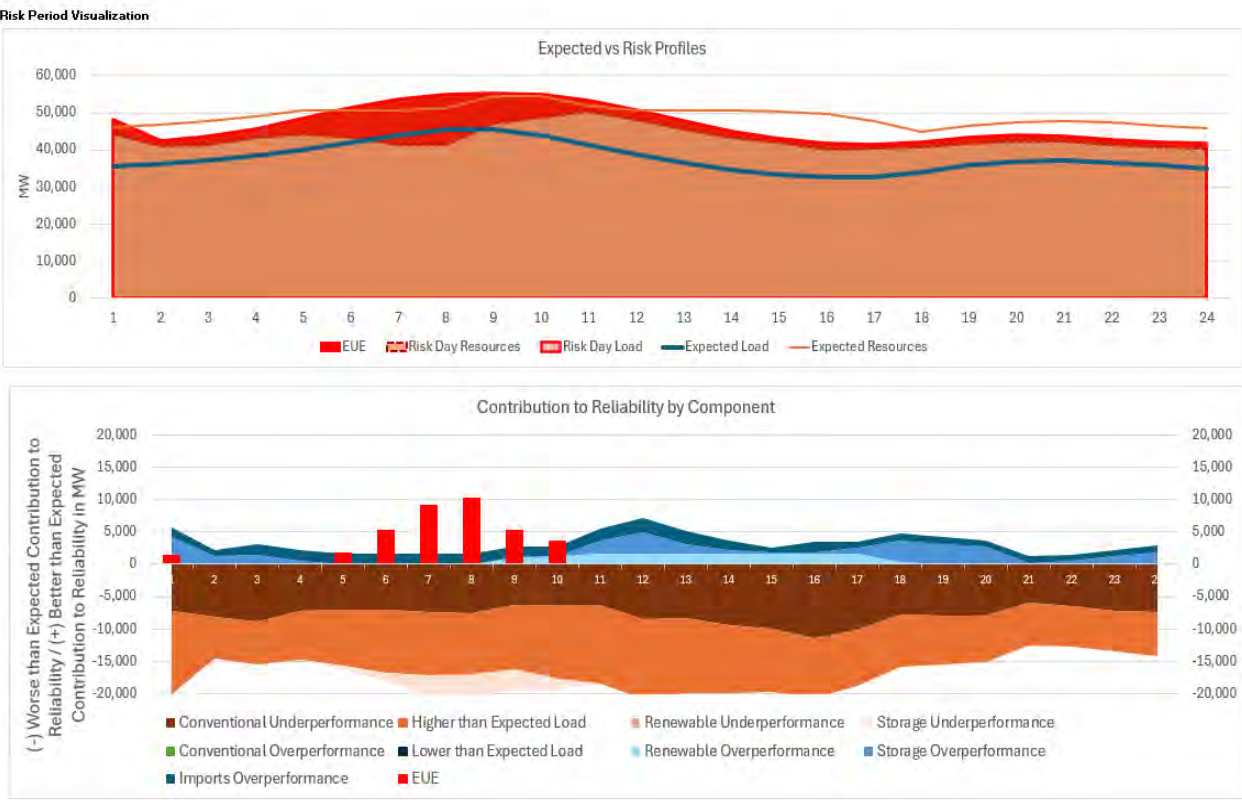
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	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, there is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProBA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

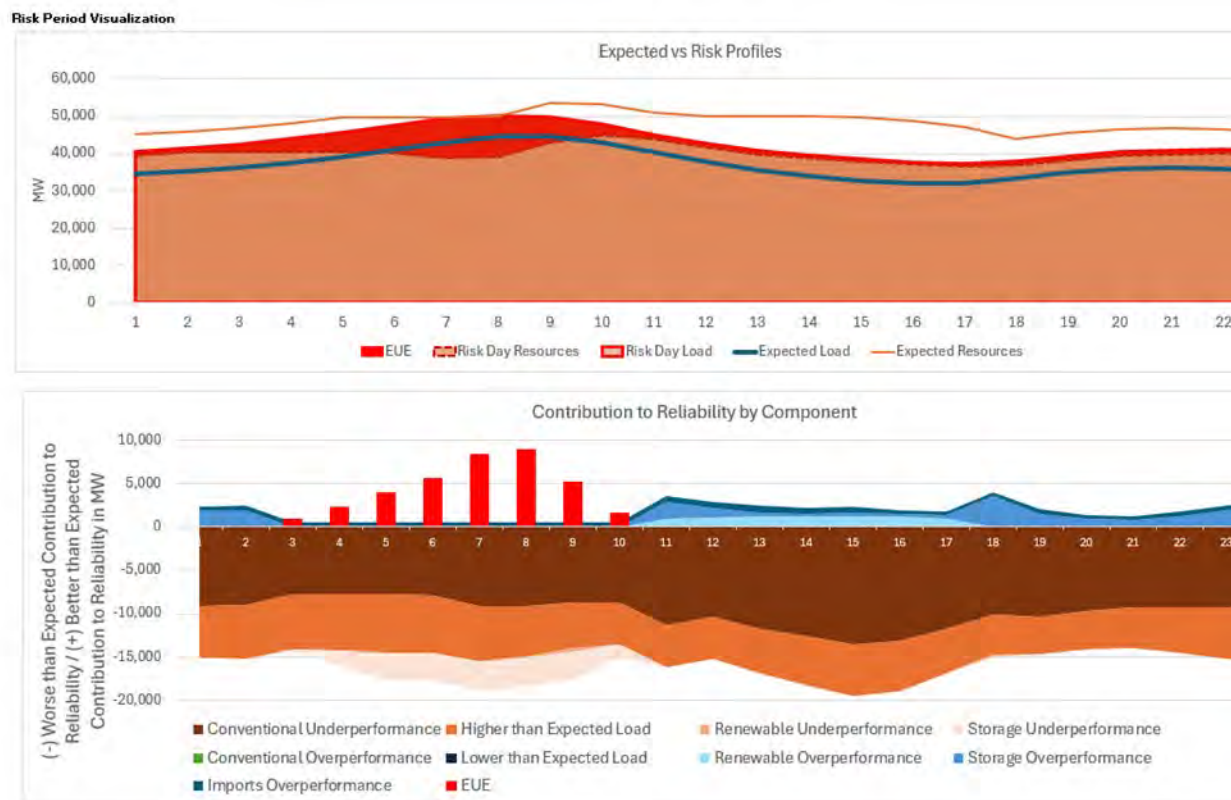
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).



Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach

for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through “High” and “Low” scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the 2024 LTRA are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity’s capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a “Bring Your Own Thermostat” initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the 2024 LTRA, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a “Bring Your Own kW” winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the 2024 LTRA, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the 2024 LTRA, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability

For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations

Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage

Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential

constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the 2024 LTRA, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

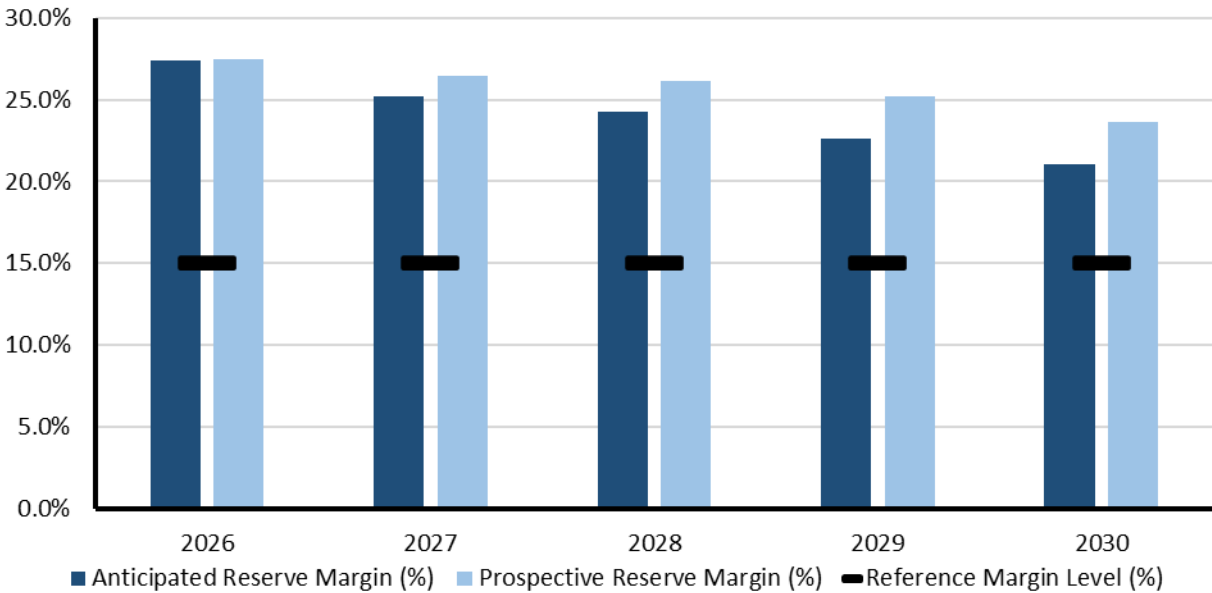


SERC-Florida Peninsula

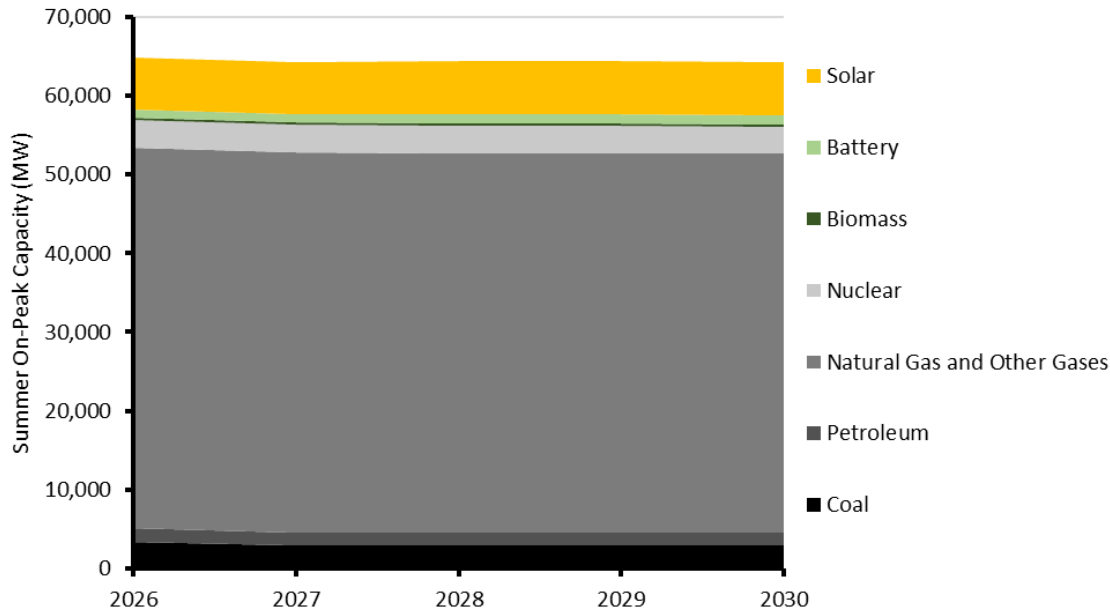
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula’s ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	64,806	63,604	63,757	63,760	63,628
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida’s Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the 2024 LTRA, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC’s ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé’s SERVVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

ProbA Results

Based on the data and assumptions of SERC’s ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

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

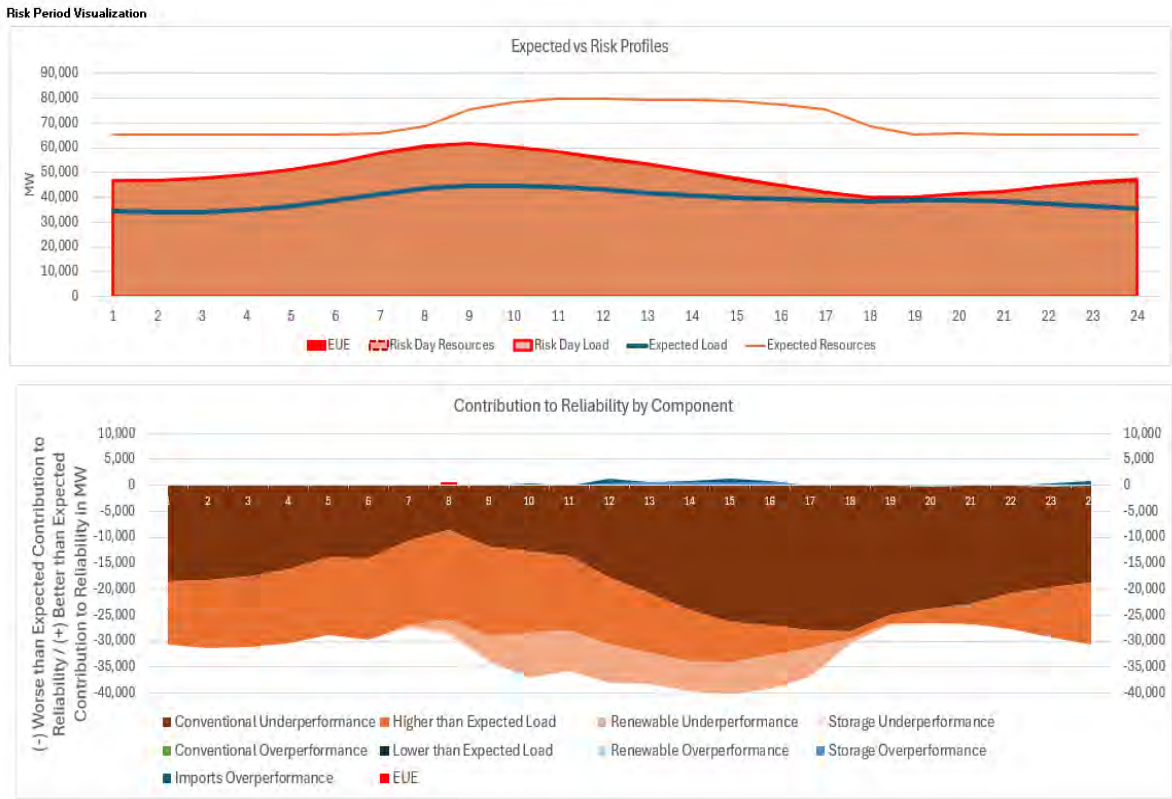
2027 EUE Heat Map

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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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%
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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%
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10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion’s approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently

develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC’s Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members’ integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
 - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
 - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
 - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
 - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
 - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
 - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk

- The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
- The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
- Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
- Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
- In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
- Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year’s reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are “not considered significant in the near-term” for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a “key area of focus.”

- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note “no expected hours of shortfall,” scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area’s “dependency on natural gas as a fuel resource” is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

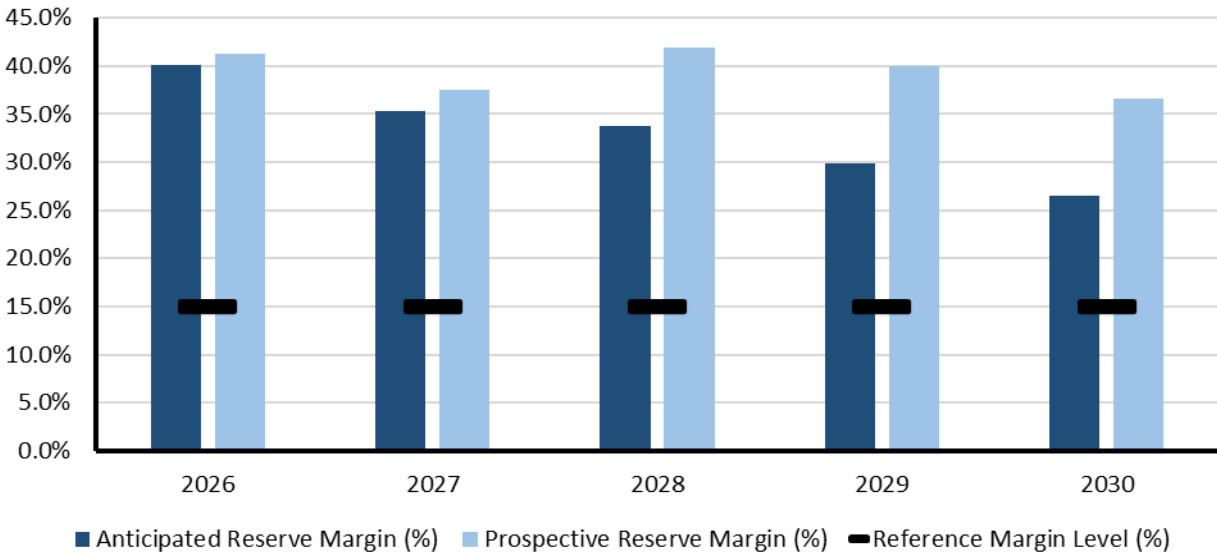


SERC-Southeast

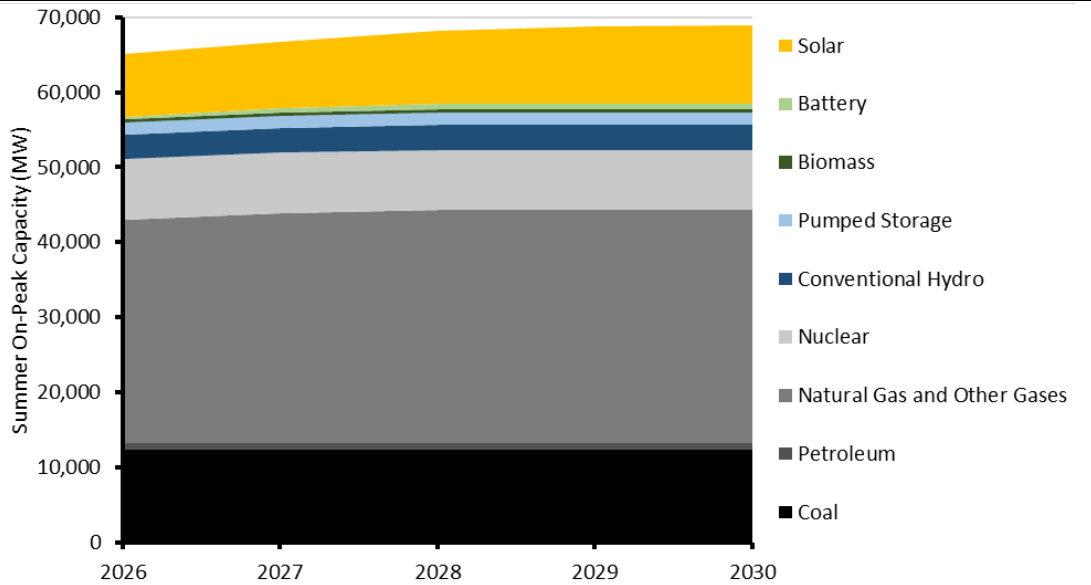
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Southeast Highlights

- SERC-Southeast’s ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to

serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001
* Provides the 2024 ProbA Results for Comparison			

The figure below shows the EUE as a Heat Map for the year 2027.

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

2027 EUE Heat Map

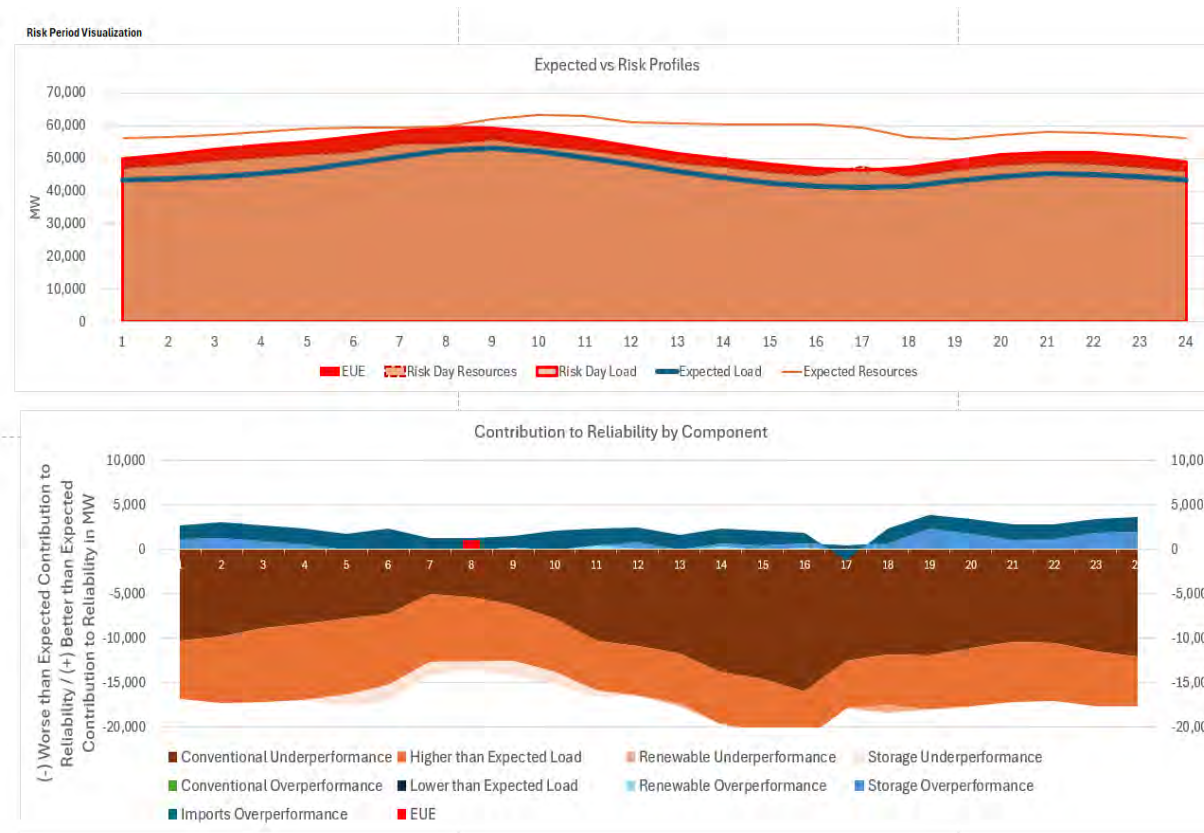
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%	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%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%	0%	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 SERVIM 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.

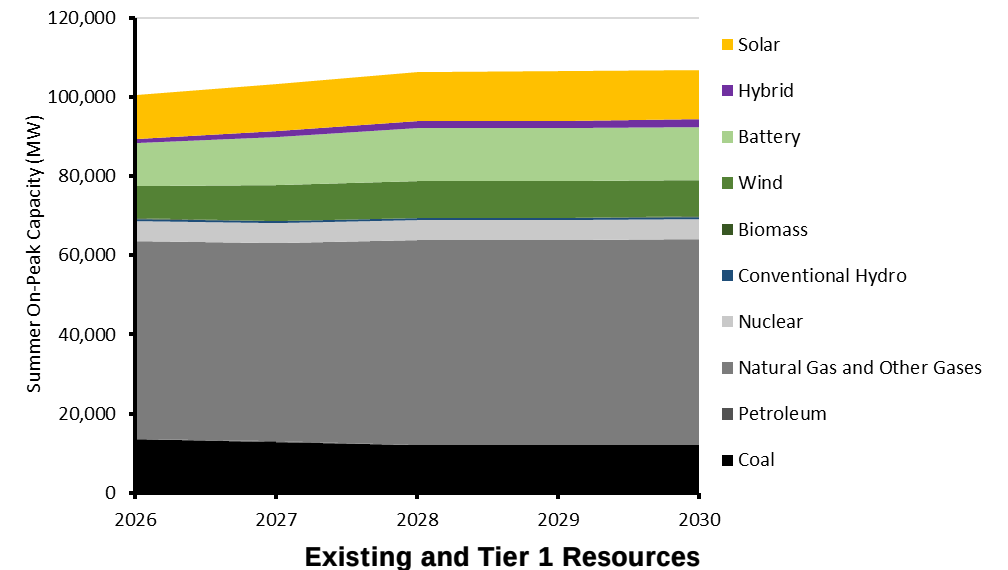
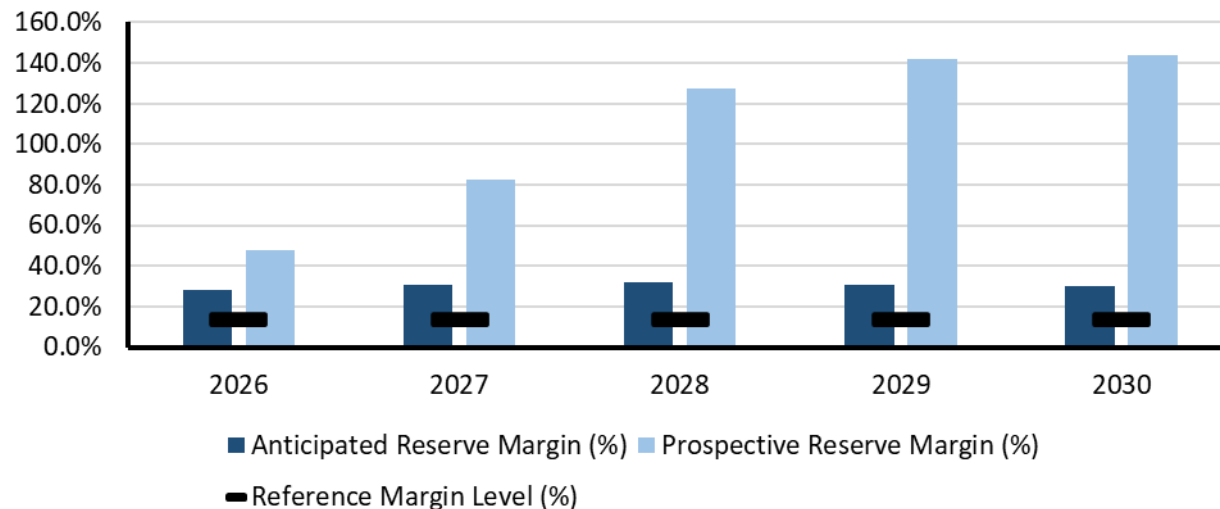


Texas RE-ERCOT

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%



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.					

Texas RE-ERCOT Assessment

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year’s LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
* Provides the 2024 ProbA Results for Comparison			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

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

2029

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

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	End of Year 2 (2027)	End of Year 5 (2030)	End of Year 10 (2035)
Data Centers	6,700	23,000	25,000
Cryptocurrency Mining Facilities	4,500	7,500	8,500
Hydrogen Electrolysis	3,000	7,902	9,100
Industrial Manufacturing Load	2,800	7,100	7,600

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT’s load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT’s authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the “Controllable and Dispatchable Demand Response” line items.

Summer	Total LL (MW)	LL Curtailment (MW)	Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9	2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5	2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5	2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5	2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6	2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5	2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3	2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9	2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6	2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4	2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6	2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called “Unregistered Distributed Generators” (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year “Reliability Must Run” (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single “integrated” generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT’s “Real Time Co-Optimization + Battery” project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy

storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT’s 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP’s 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT’s Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

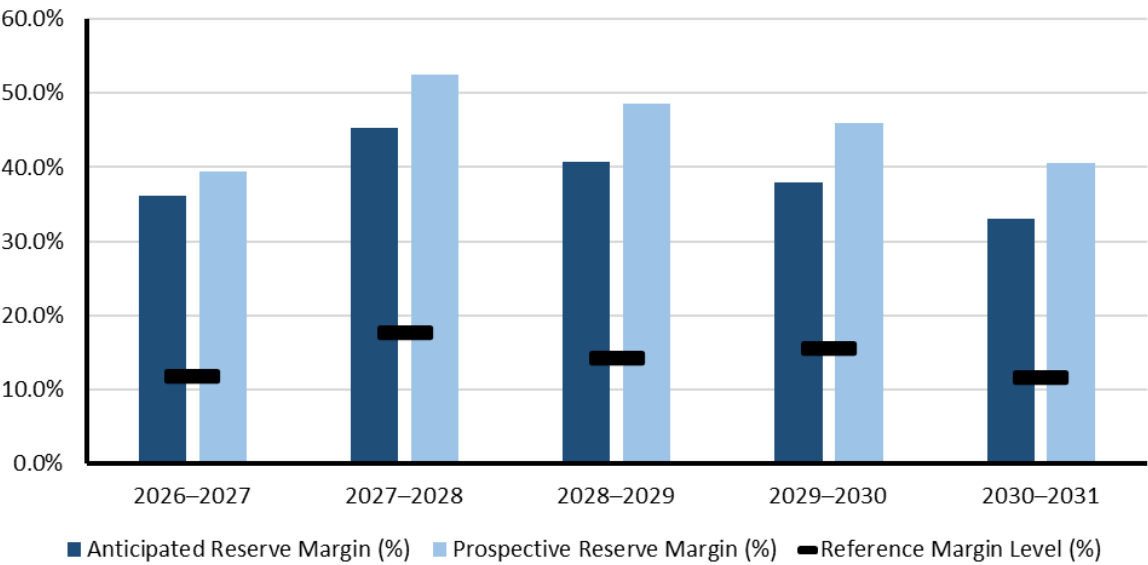


WECC-Alberta

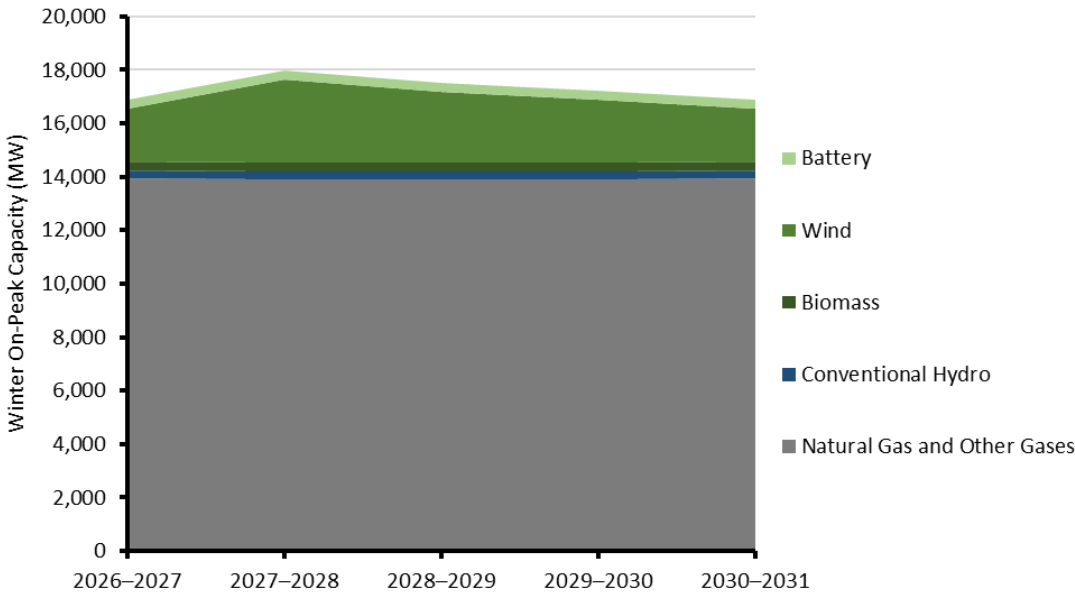
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province’s Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta’s transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta’s ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta’s total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta’s thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta’s 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins

WECC-Alberta’s ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk

AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

Demand

Alberta’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management

AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation

Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO’s ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC’s load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO’s system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta’s natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is [30% renewable by 2030](#). Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to the NERC's [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

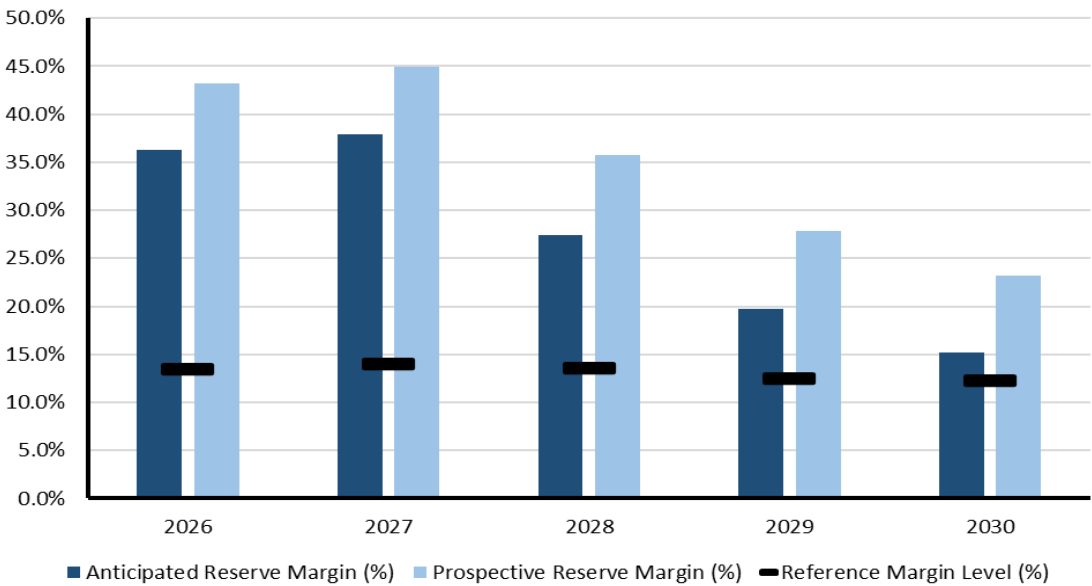


WECC-Basin

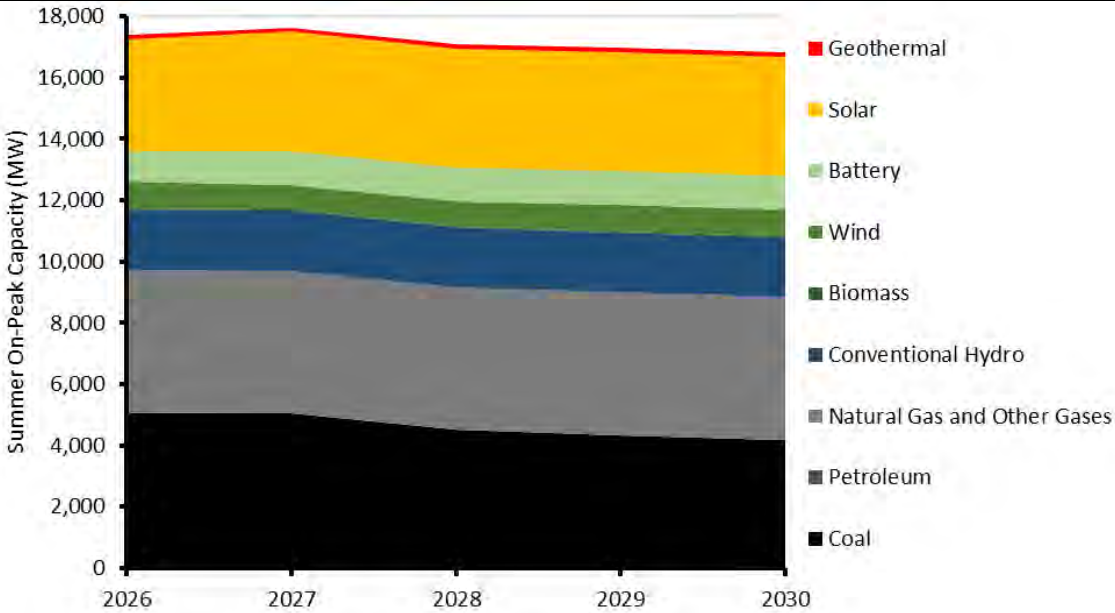
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp’s eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	17,428	17,672	17,130	17,003	16,839

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

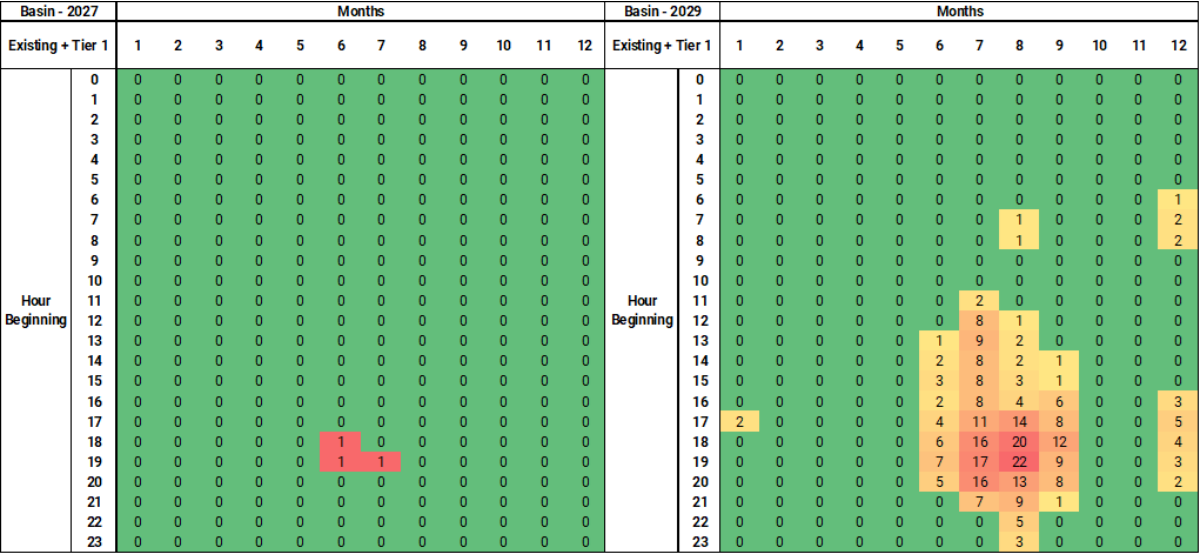
Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC’s internally developed modeling tool that performs energy based ProbAs that support NERC’s LTRA and seasonal assessments, as well as WECC’s Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area’s ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

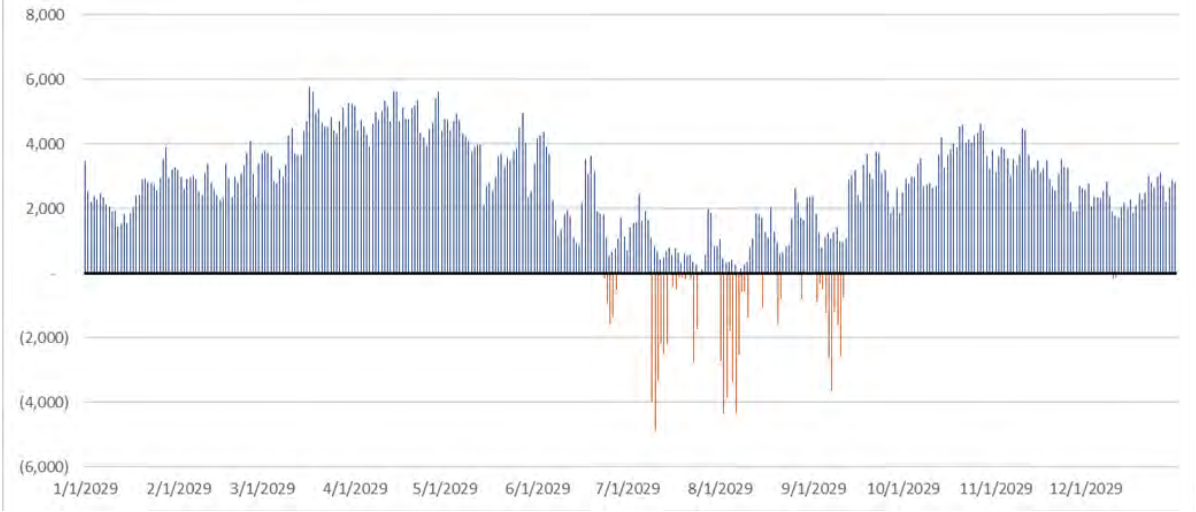
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
* No prior results as the assessment area is new for the 2025 LTRA.			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.



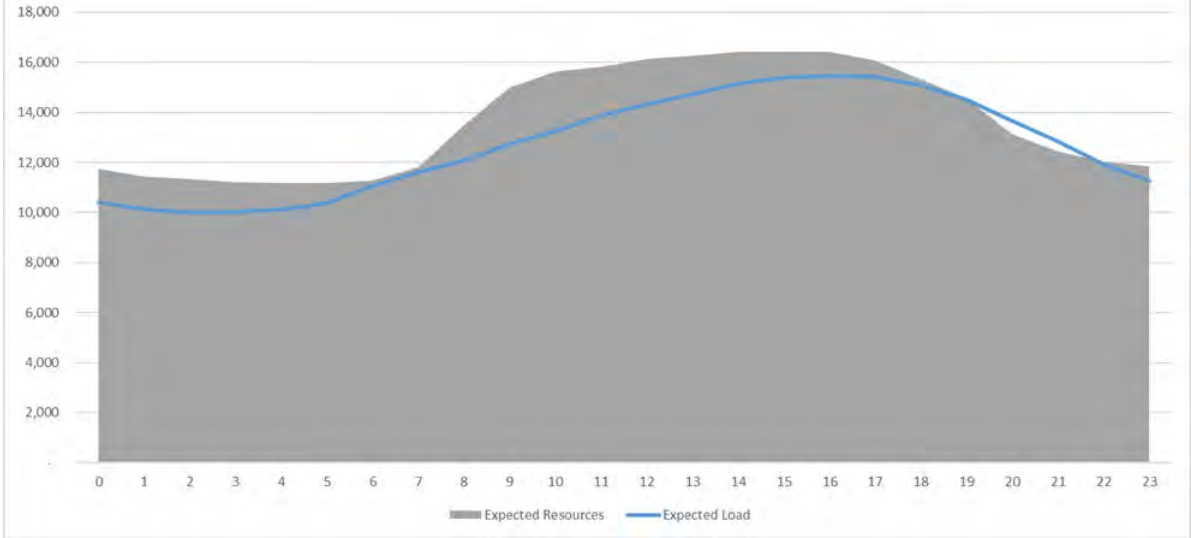
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin’s resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company’s dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting [100% clean electricity by 2045](#); Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's [Energy Gateway Transmission Plan](#) addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

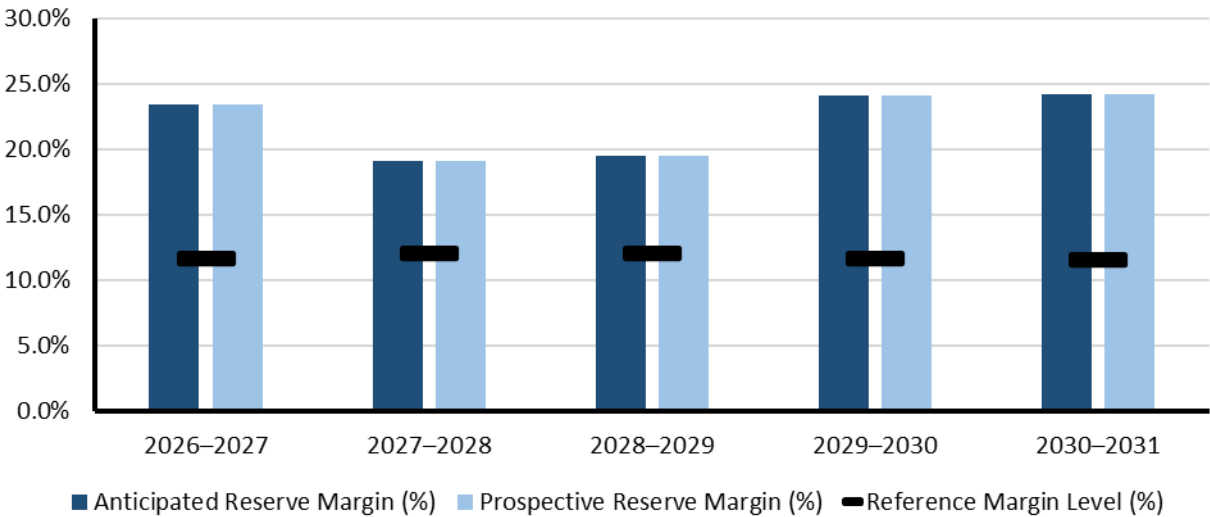


WECC-British Columbia

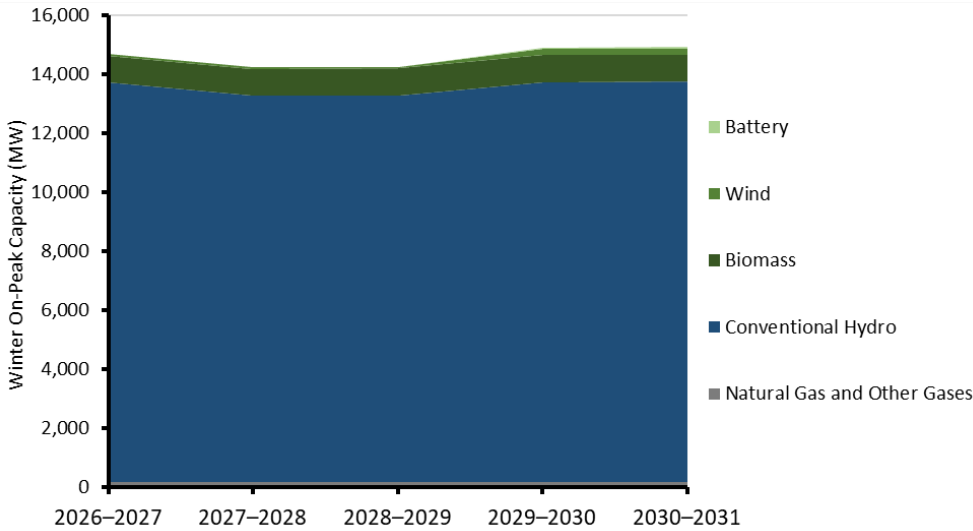
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro’s transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-British Columbia Highlights

- WECC-British Columbia’s anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro’s most recent 10-year capital plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia’s ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For [2025–2026 Winter](#), monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For [2026 Summer](#), a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The [CleanBC Roadmap](#) states, “By 2030, BC will phase out BC Hydro’s last gas-powered facility so the electricity we make is 100% clean.”

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia’s capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province’s basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year’s snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC’s natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC’s [*ITCS Canadian Analysis*](#), the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro’s most recent 10-Year Capital Plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

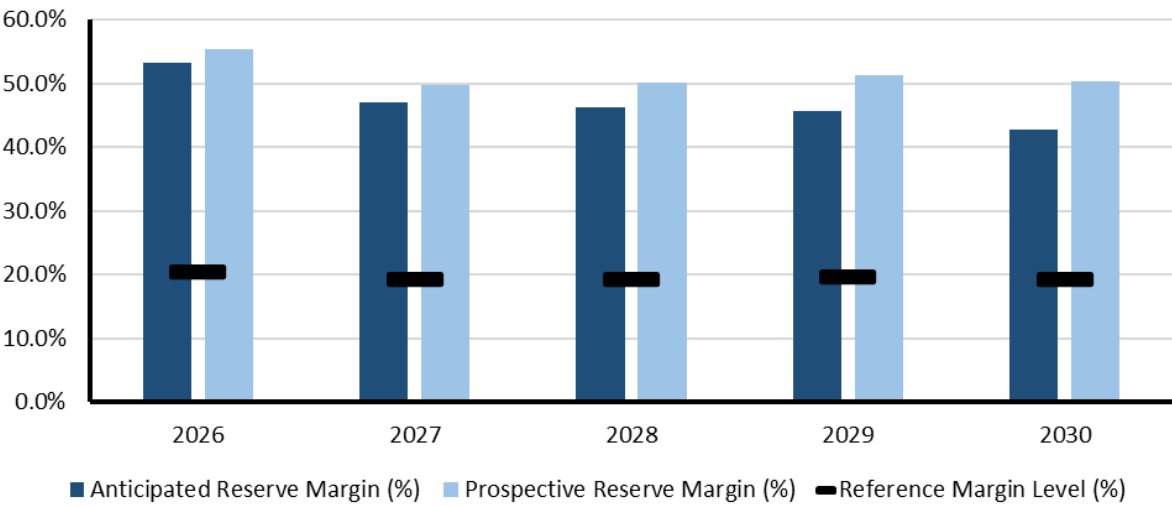


WECC-California

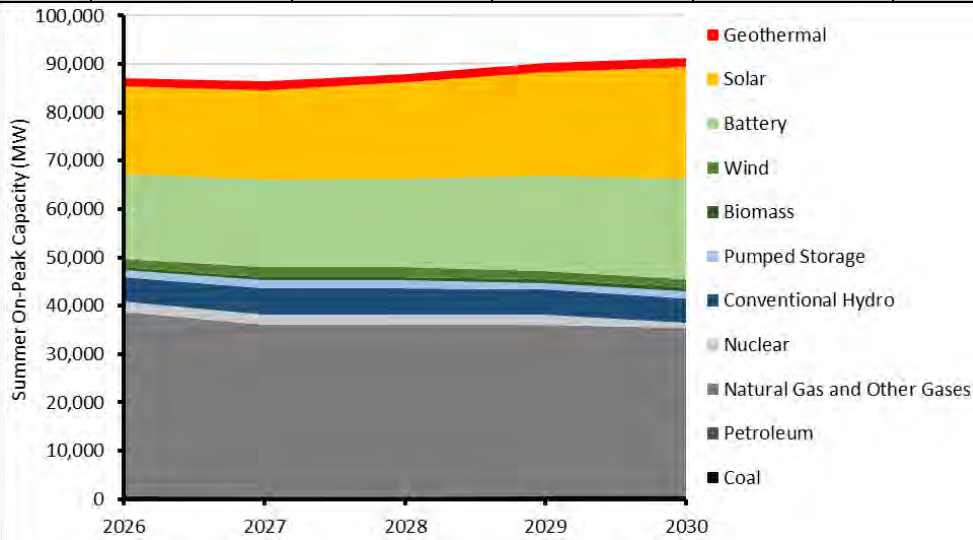
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. [CPUC’s ruling](#) also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-California Assessment

Planning Reserve Margins

The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC’s reserve margins are not used in WECC’s methodology for the LTRA.

Energy Assessment, including non-peak hour risk

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

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand

Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management

DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources

A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the “net billing tariff” that pays approximately 75% lower rates for energy sent back to the grid. Given California’s shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

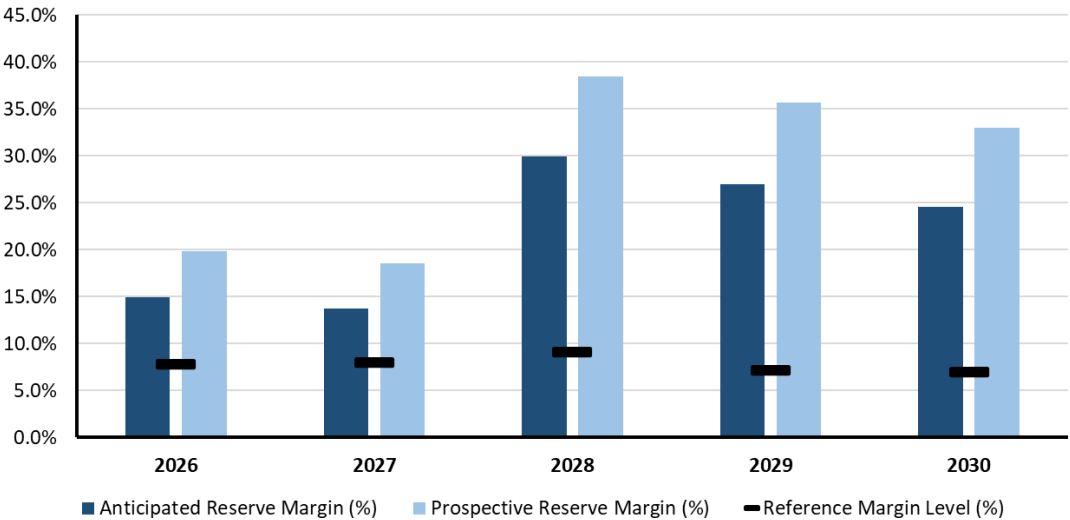


WECC-Mexico

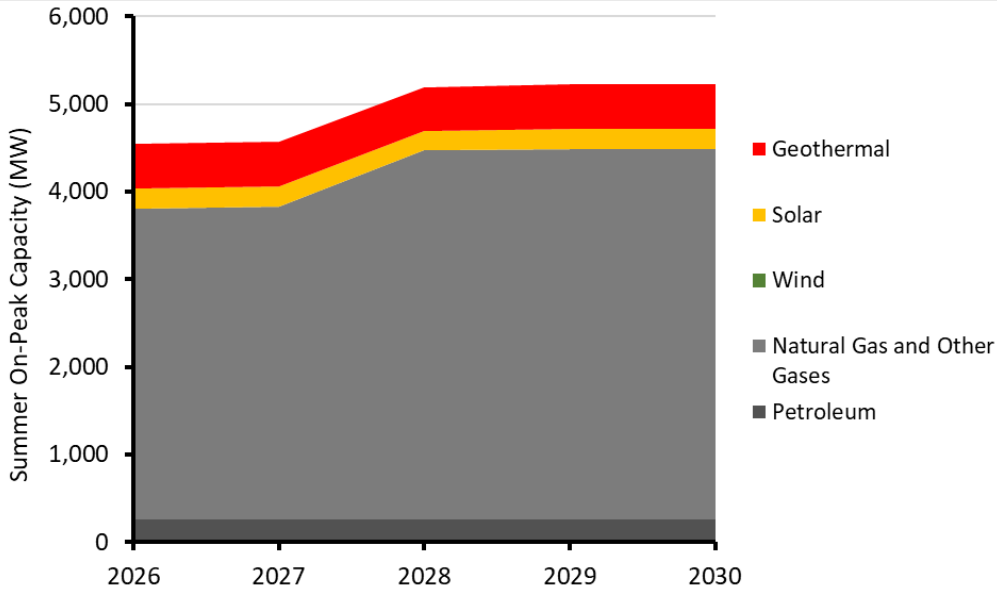
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins

The ARM is above the RML until 2035, the last year of the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

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

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Demand

Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation

Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: [WECC Path Rating Catalog](#)) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

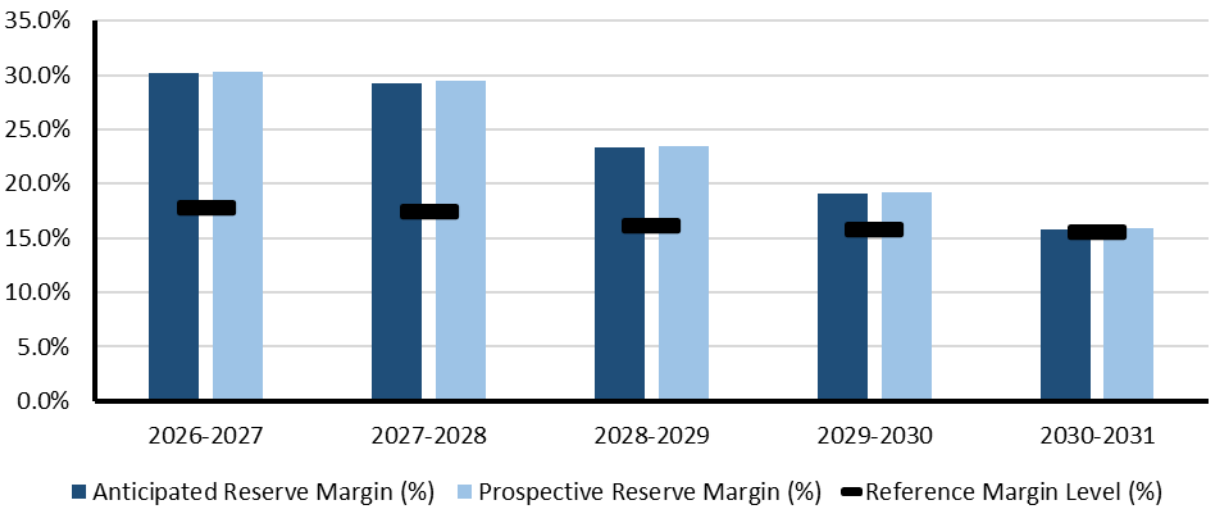


WECC-Northwest

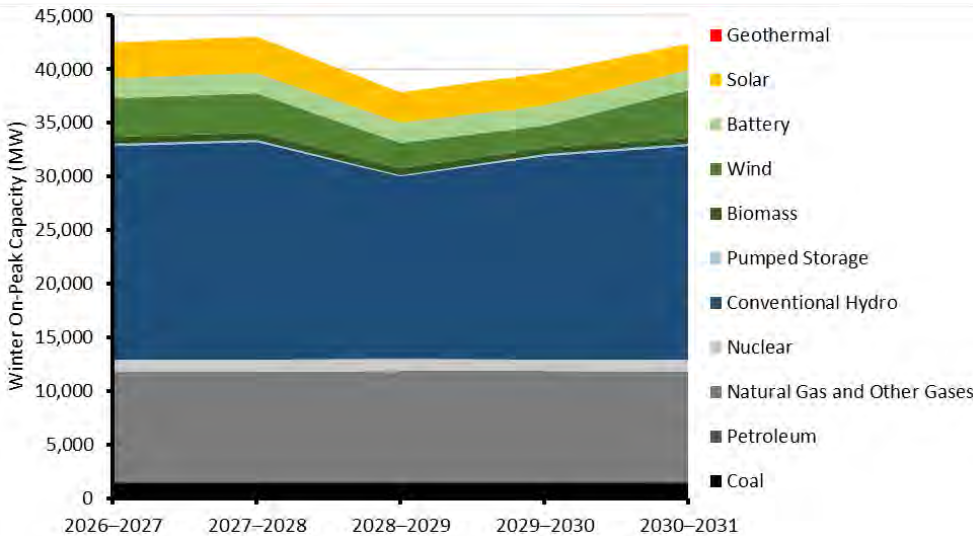
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the [WRAP Area Map](#).
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

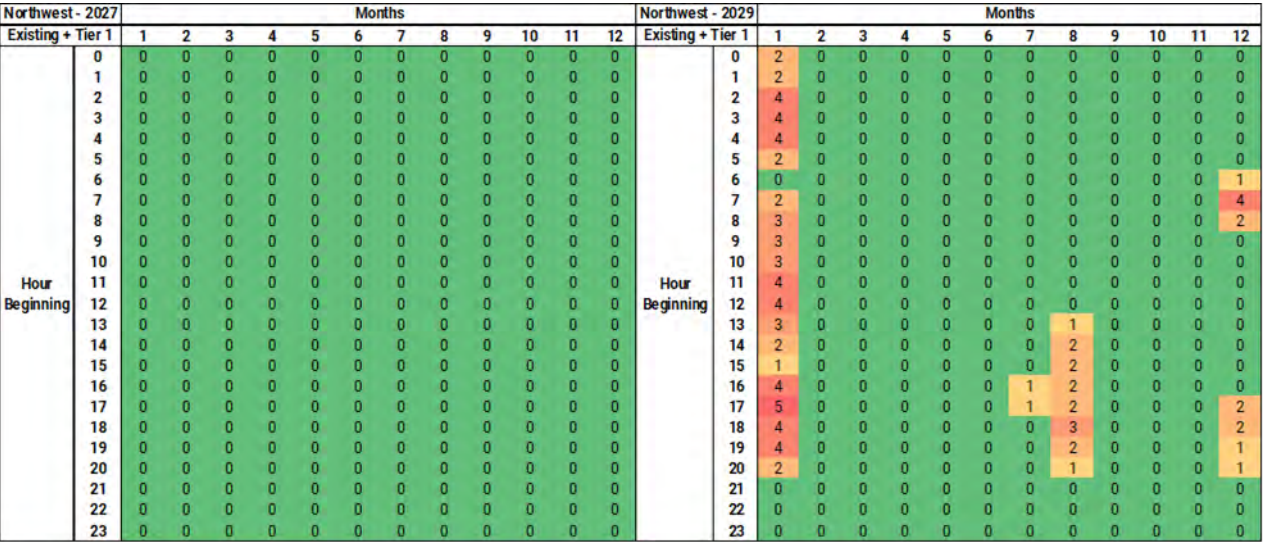
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

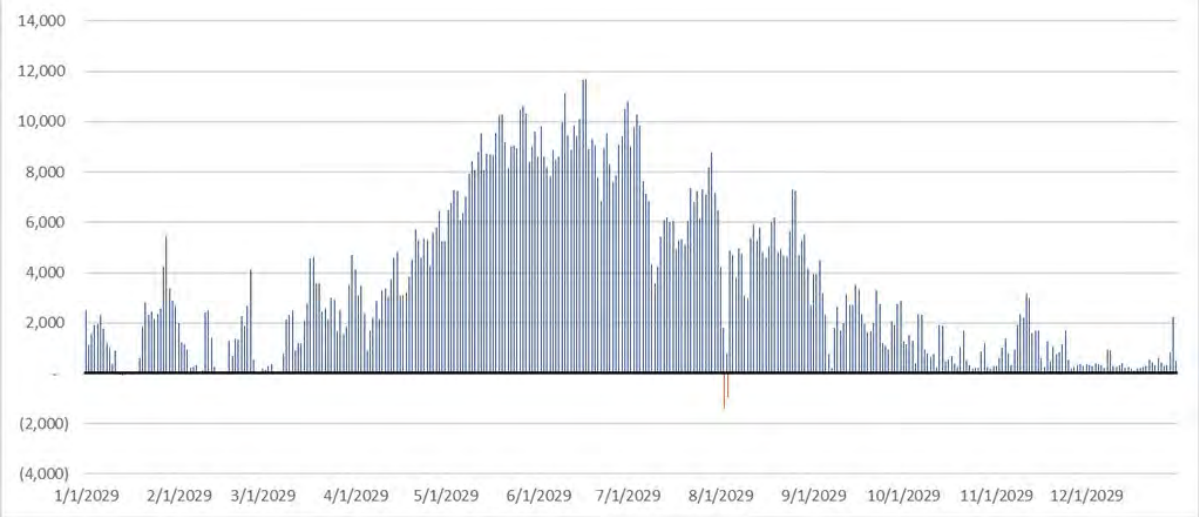
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.



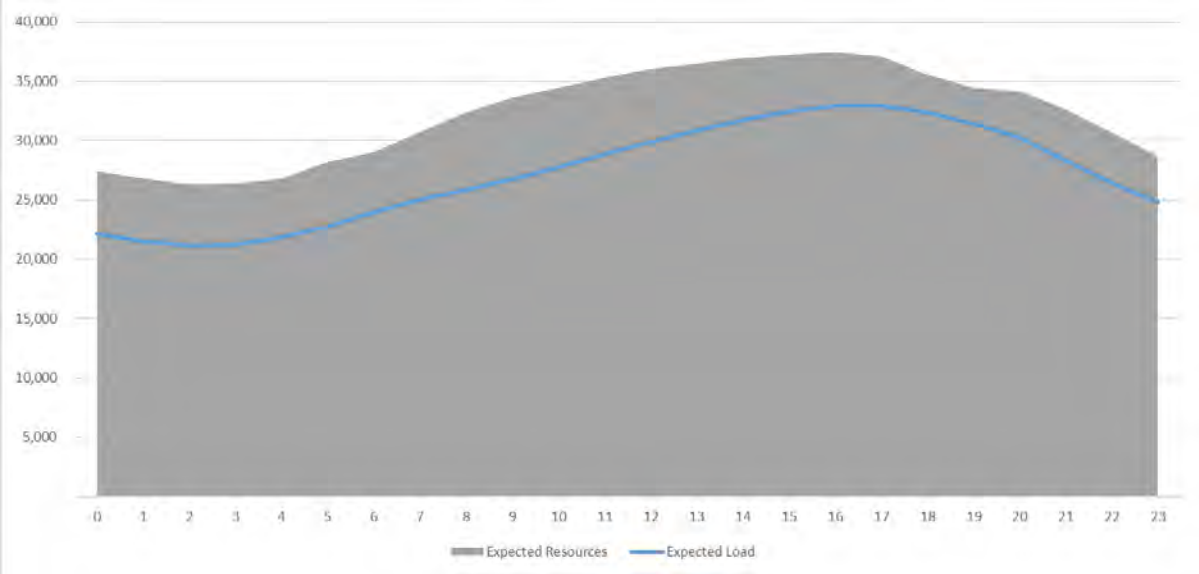
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

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.

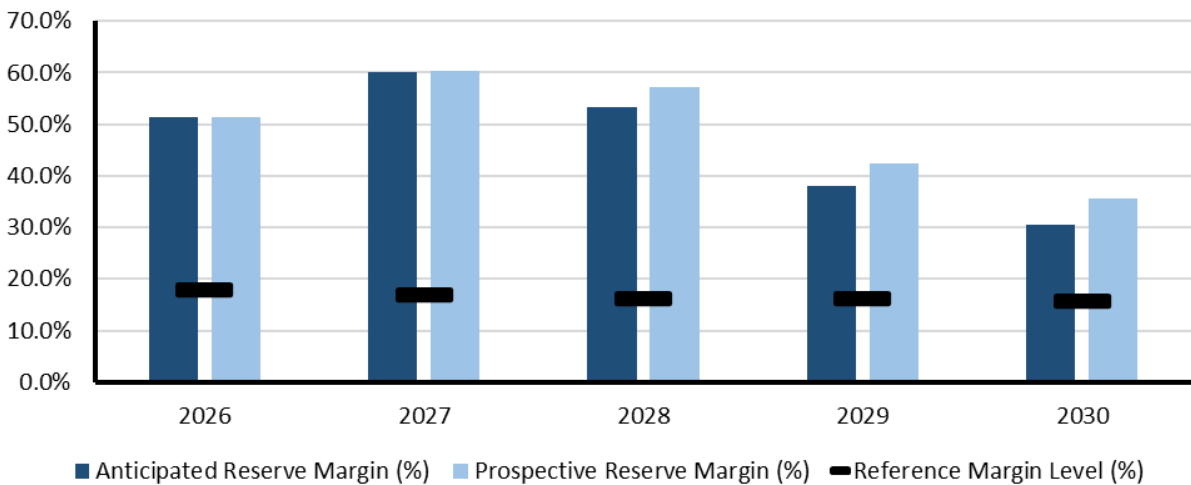


WECC-Rocky Mountain

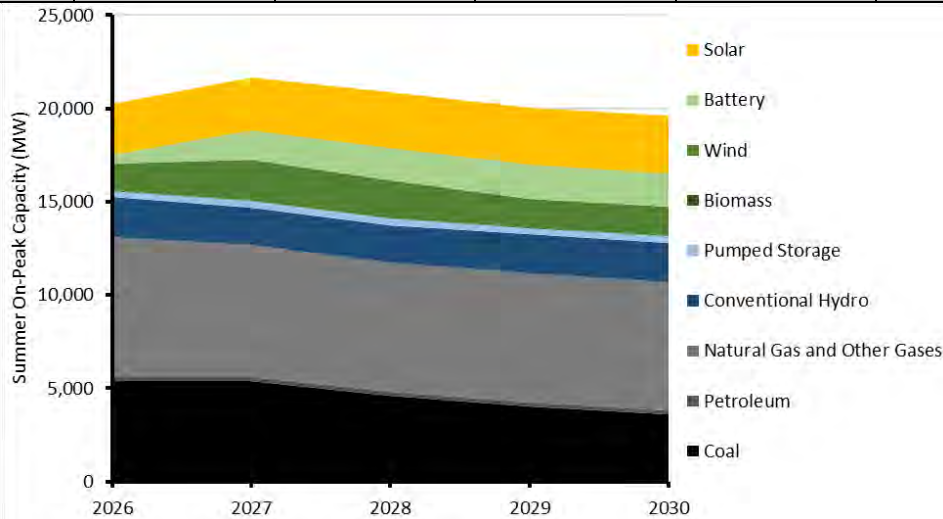
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and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

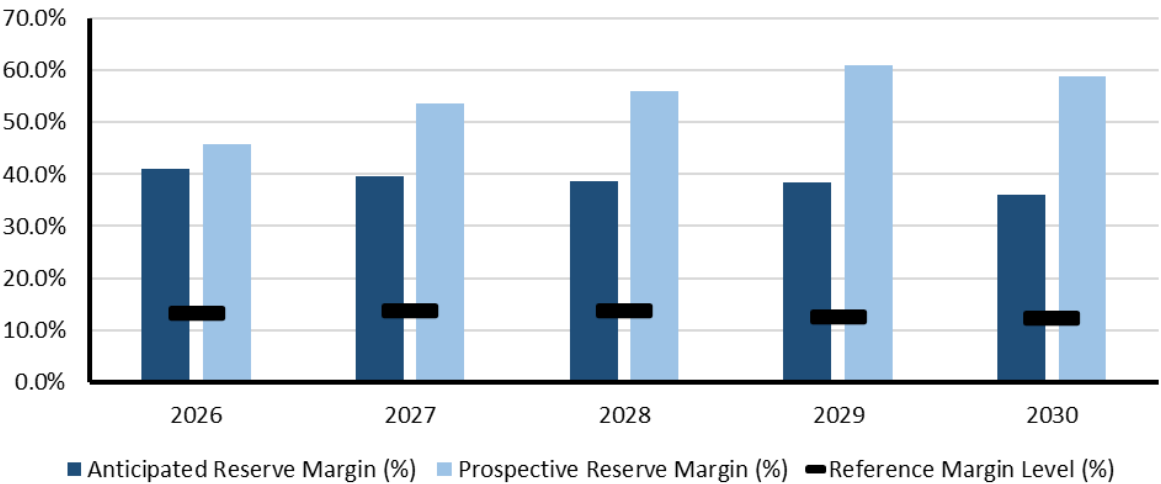


WECC-Southwest

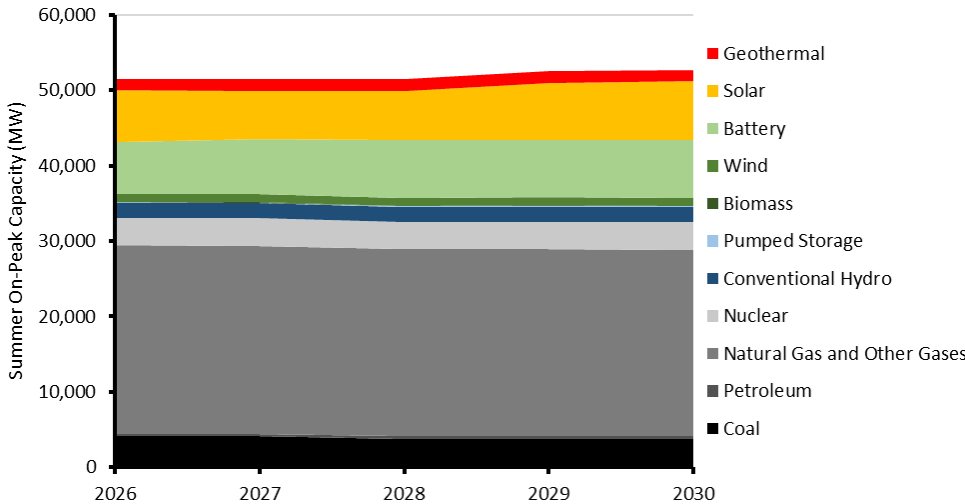
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for 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 Resources⁵³ - 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 retirements⁵⁴			
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 curtailment⁵⁸
- 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 <i>FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States</i> 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 filings 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 <i>IBR Activities Reference Guide</i>.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 IBR Activities](#)

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, <i>Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System</i> , incorporated the <i>Design Basis for Natural Gas Study</i> 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
<i>Interregional Transfer Capability Study (ITCS)</i>	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 <i>2025 LTRA</i> 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 <i>Energy Assurance with Energy Constrained Resources</i>.⁹⁰ In other Reliability Standard development work, Project 2023-07 <i>Transmission System Planning Performance Requirements for Extreme Weather</i> 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 <i>DER Activities Reference Guide</i> . 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)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit XX: Department, Order No. 202-26-16 (Feb. 17, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-16

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a “speed closure” of the Campbell Plant fifteen years before the end of its scheduled design life.³ Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant’s retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3 and 202-25-7, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, and November 19, 2025, respectively. Subsequently, Order No. 202-25-9, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until February 17, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.⁴ I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods, which would help

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan’s Clean Energy Transformation* (June 23, 2021), <https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation>.

⁴ See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-9, at 3-7 (Nov. 18, 2025).

prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.⁵ I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.⁶ My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”⁷ In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.⁸

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”⁹ Additionally, EIA stated, “[t]ypically, Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”¹⁰ The state’s Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, “Holtec International expects the Palisades plant in Michigan to resume service early next year”¹¹

Third, the Campbell Plant’s retirement would have further decreased available dispatchable generation within MISO’s service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant

⁵ See, e.g., *Id.* at 7-8.

⁶ See, e.g., *Id.* at 8.

⁷ NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025) (NERC 2025 Summer Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

⁸ *Id.*

⁹ EIA, *Michigan State Profile and Energy Estimates* (Oct. 17, 2024), <https://www.eia.gov/state/print.php?sid=MI>.

¹⁰ *Id.*

¹¹ L.A. TIMES, *Nuclear plants face decadelong timeline to meet AI energy needs* (Nov. 13, 2025), <https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs>.

into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC still anticipates “elevated risk of operating reserve shortfalls.”¹²

Fourth, MISO’s Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.”¹³ While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance.”¹⁴ According to MISO, these results “reinforce the need to increase capacity.”¹⁵

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9 continue, both in the near and long term.¹⁶ The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency’s data, from June 2025 through December 2025,¹⁷ the Campbell plant has generated an average of approximately 561,100 MWh per month, providing vital generation capacity to the region. From June 11, 2025 through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response

¹² NERC 2025 Summer Reliability Assessment at 16.

¹³ MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025– 2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

¹⁴ *Id.* at 12.

¹⁵ *Id.* at 2. For further information regarding the determination that emergency conditions existed, see *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (Aug. 20, 2025).

¹⁶ Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. See Order No. 202-25-7 at 1, n.1.

¹⁷ See, *Custom Data Download, EPA CAMPD (Clean Air Markets Program Data)*, <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “June, July, August, September, October, November, December.” The data can then be filtered to only include the J.H. Campbell Plant.).

to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁸ MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."¹⁹ MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.²⁰

In December of 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."²¹ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.²² MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.²³

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.²⁴ In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

¹⁸ MISO, *Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct*, FERC Docket No. ER22-495-000 (Nov. 30, 2021) (MISO Transmittal Letter). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

¹⁹ MISO Transmittal Letter at 3.

²⁰ *Id.* at 3-4.

²¹ MISO, *Attributes Roadmap* (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

²² *Id.* at 11.

²³ *Id.*

²⁴ MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.²⁵

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁶ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²⁷ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²⁸ This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²⁹ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”³⁰ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”³¹ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”³²

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves in above-normal conditions.”³³ These findings were echoed in NERC’s 2024 – 2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to the

²⁵ *Id.* at 12.

²⁶ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²⁷ *Id.* at 7.

²⁸ *Id.* at 8.

²⁹ *Id.* at 43.

³⁰ *Id.* at 15.

³¹ *Id.*

³² *Id.*

³³ NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”³⁴

MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 event for MISO’s North and Central Regions due to generational outages, high demand, and transfer capability limits.³⁵

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Michigan.³⁶

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁷ The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.³⁸ The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.³⁹ Similar results were projected for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.⁴⁰

³⁴ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

³⁵ See MISO Notifications Overview, *Real-Time Operations*, <https://www.misoenergy.org/markets-and-operations/notifications/>.

³⁶ MISO 2025 – 2026 Planning Resource Auction at 13.

³⁷ OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³⁸ *Id.* at 2.

³⁹ *Id.* at 7.

⁴⁰ *Id.* at 9.

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.⁴¹ Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.⁴²

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025,⁴³ and the ERAS should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.⁴⁴ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.⁴⁵ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary

⁴¹ *Id.* at 7, 9.

⁴² *Id.*

⁴³ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

⁴⁴ *Id.* P 84.

⁴⁵ See generally S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), <https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>. “With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”

threat to our Nation’s economy, national security, and foreign policy.”⁴⁶ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”⁴⁷ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴⁸

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴⁹ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.⁵⁰ In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and “continue[s] to see positive momentum with data centers within the 9 GW pipeline”⁵¹

⁴⁶ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴⁷ *Id.*

⁴⁸ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴⁹ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁵⁰ Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan* (last accessed Aug. 13, 2025), <https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan>.

⁵¹ See Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), <https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/>.

Grid operators — including MISO itself — have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁵² Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁵³ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁵⁴

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁵⁵ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

⁵² *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcommittee on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

⁵³ *Id.* at 6.

⁵⁴ *Id.* at 7.

⁵⁵ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

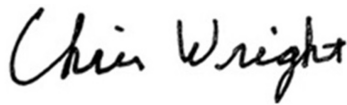
To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation until May 18, 2026.⁵⁶

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

- A. From February 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By March 4, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

⁵⁶ 16 U.S.C. § 824a(c)(4).

- E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.
- H. This Order shall be effective on February 17, 2026, through May 18, 2026, with the exception of applicable compliance obligations in paragraph D.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit YY: Department, Order No. 202-26-17 (Feb. 23, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-17

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04 and 202-25-08, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain in operation for 90 days, until August 28, 2025, and November 26, 2025, respectively. Subsequently, Order No. 202-25-10, issued pursuant to FPA section 202(c), required the Eddystone Units to remain in operation for 90 days, until February 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.³ I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.⁴ I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.⁵ My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See, e.g., *PJM Interconnection, L.L.C. and Constellation Energy Corp.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).

⁴ See, e.g., *id.*

⁵ See, e.g., *id.* at 8, Ordering Paragraph A.

dispatchable resources, and other factors.⁶ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM’s interconnection queue.⁷ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”⁸ In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.⁹

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”¹⁰

⁶ *Keeping the Lights On: Examining the State of Regional Reliability: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy & Com.*, 119th Cong., at 4-5 (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.), <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

⁷ *Id.* See also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, “it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM’s interconnection queue pose increasing reliability risks through 2030.”).

⁸ PJM Inside Lines, *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk* (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁹ PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, at 1 (Feb. 24, 2023) (Four Rs Report).

¹⁰ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 continue, both in the near and long term.¹¹ The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency, the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,¹² providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.¹³

PJM's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 – February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/ Load Management Alert and an EEA 1.¹⁴ Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) “that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency.”¹⁵ The Department granted PJM's application and issued Order No. 202-26-02 on

¹¹ Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. If Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

¹² See *Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “June, July, August, September, October, November, December.” The data can then be filtered to include only the Eddystone Generating Station.

¹³ See PJM, *Emergency Procedures*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search range set to: effective from 06/01/2025 until 08/31/2025).

¹⁴ See *id.* (search range set to: effective from 01/20/2026 until 02/07/2026).

¹⁵ PJM, *Request for Emergency Order Under Federal Power Act, Section 202(c)*, at 2 (Jan. 24, 2026), <https://www.energy.gov/documents/pjm-202c-application-2026-01-24>.

January 25, 2026.¹⁶ On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was granted by the Department on the same day.¹⁷

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.¹⁸ PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."¹⁹ Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.²⁰

The evidence indicates that there is also a potential longer term resource adequacy emergency in the PJM region. In a news release expressing support for Order No. 202-25-04, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."²¹

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.²² PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for

¹⁶ *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

¹⁷ *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

¹⁸ PJM Inside Lines, *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand* (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

¹⁹ PJM Inside Lines, *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand* (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

²⁰ PJM Resource Adequacy Planning Special Planning Committee, *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

²¹ PJM Inside Lines, *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30* (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint" *Id.*

²² Four Rs Report at 2.

renewable projects is approximately 5%.²³ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”²⁴ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.²⁵

In its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report”²⁶ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”²⁷ PJM went on to explain that its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers,” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.²⁸ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”²⁹ Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.³⁰

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”³¹ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme” forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.³²

²³ *Id.*

²⁴ *Id.* at 16, Table 1.

²⁵ *Id.*

²⁶ PJM, *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712, at 10 (Dec. 13, 2024).

²⁷ *Id.*

²⁸ *Id.* at 10-11. *See also id.* at 13 (“the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . .”).

²⁹ *Id.* at 14.

³⁰ *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.”).

³¹ Affidavit of Mr. Donald Bielak at P 10.

³² *Id.* at P 12.

On February 11, 2025, FERC accepted PJM’s RRI filing.³³ In its order on rehearing, FERC concluded that “PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest.”³⁴

The North American Electric Reliability Corporation (NERC) has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observes that the PJM region is at high risk of energy shortfalls over the next five years³⁵ and faces significant reliability challenges as “[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements.”³⁶ The assessment notes that “[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;” however “[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays.”³⁷ Overall, the assessment concludes that “[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.”³⁸

Order Nos. 202-25-04, 202-25-08, and 202-25-10 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our nation’s economy, national security, and foreign policy.”³⁹ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international

³³ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

³⁴ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

³⁵ NERC, *2025 Long-Term Reliability Assessment*, at 7, Figure 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

³⁶ *Id.* at 8.

³⁷ *Id.* at 16.

³⁸ *Id.* at 91.

³⁹ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

commodity markets.”⁴⁰ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴¹

Further, the Department detailed the myriad challenges affecting the nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴² The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.⁴³ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.⁴⁴ In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.⁴⁵ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.⁴⁶

⁴⁰ *Id.*

⁴¹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴² U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025) (Resource Adequacy Report), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁴³ See PPL Corporation, *PPL Corporation Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINA L.pdf.

⁴⁴ See Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

⁴⁵ Resource Adequacy Report at 28.

⁴⁶ *Id.* at 27.

Grid operators, including PJM, have likewise acknowledged the nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."⁴⁷ Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."⁴⁸ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁴⁹ Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."⁵⁰

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."⁵¹ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

⁴⁷ Asthana Test. at 4.

⁴⁸ *Id.*

⁴⁹ *Id.* at 9-10.

⁵⁰ *Id.* at 10.

⁵¹ Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain in operation through May 24, 2026.⁵²

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

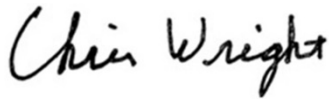
- A. From February 24, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By March 11, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this

⁵² 16 U.S.C. § 824a(c)(4).

Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

- E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.
- H. This Order shall be effective on February 24, 2026, through May 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of February 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	
	)	

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

Exhibit ZZ: Department, Order No. 202-26-18 (Mar. 16, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-18

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation ("Centralia") is an electric generating facility in Centralia, Washington. Centralia is owned and operated by the TransAlta Centralia Generation LLC ("TransAlta"). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.³ Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 was slated to cease operation in December 2025 based on a 2011 Washington law⁴ and a subsequent agreement between TransAlta and the State of Washington.⁵ TransAlta has announced plans to convert the unit to natural gas by 2028.⁶

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data (2024)* (2024 Form EIA-860), (September 09, 2025), <https://www.eia.gov/electricity/data/eia860/>.

⁴ Act of Apr. 29, 2011, Ch. 180, 2011 Wash. Laws, <https://leg.wa.gov/CodeReviser/documents/sessionlaw/2011pam4.pdf>.

⁵ See MOA (Dec. 23, 2011), <https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf> ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . ."); see also First Amendment to MOA (July 13, 2017), <https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf>. As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. Those orders were based on my determination that emergency conditions existed in the WECC Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.

Specifically, I determined that the WECC Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.⁷ I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.⁸ I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.⁹ My determination was based on a number of facts.

First, in its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.¹⁰ The assessment notes that “there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year.”¹¹

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that “[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030”¹² and that “[l]oad growth and retirements mean the region faces a

would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁶ TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025), <https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/>.

⁷ See, e.g., *TransAlta*, Order No. 202-25-11, at 1 (Dec. 16, 2025).

⁸ See, e.g., *id.* at 1-3.

⁹ See, e.g., *id.* at 3-4.

¹⁰ NERC, *2025-2026 Winter Reliability Assessment*, at 6 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

¹¹ *Id.*

¹² E3, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, at 2 (Sept. 22, 2025), <https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20>

power supply shortfall in 2026.”¹³ E3 reported that nearly 9000 MW of new capacity will be needed in the region by 2030, but currently only 3000 MW of projects for new capacity are in active development.¹⁴ Overall, E3 found that “[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs” and “[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures.”¹⁵

EMERGENCY SITUATION

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11 and 202-25-11B continue, both in the near and long term.¹⁶ The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC Northwest region. According to the U.S. Environmental Protection Agency’s data, in 2025,¹⁷ Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.¹⁸ NERC assessed that the WECC Northwest region is at high risk of energy shortfalls over the next five years,¹⁹ noting that “[r]apid forecasted demand growth is driving the need for more resources” and that “[p]eriods of unserved energy are projected for both summer and winter.”²⁰ The assessment notes that peak load in the region “is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest.”²¹ Additionally, while over 10 GW of new variable resources are in development, the assessment warns that “additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.”²²

On February 25, 2026, a preliminary injunction was issued by the United States District Court for the District of Oregon that imposes operational constraints on the dams

WA%20RA%20Meeting.pdf. *See also id.* for the list of E3’s study sponsors, which include certain “regional utilities and generation owners.”

¹³ *Id.* at 10.

¹⁴ *Id.*

¹⁵ *Id.* at 2.

¹⁶ *See, e.g.*, Order No. 202-25-11 at 1.

¹⁷ *See Custom Data Download, EPA CAMPD (Clean Air Markets Program Data)*, <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “January, February, March, April, May, June, July, August, September, October, November, December.” The data can then be filtered to only include the Centralia).

¹⁸ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

¹⁹ *Id.* at 7.

²⁰ *Id.* at 8.

²¹ *Id.* at 19.

²² *Id.* at 19.

that comprise the Federal Columbia River Power System.²³ The restrictions imposed by the preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC Northwest assessment region.²⁴ The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.²⁵ BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.²⁶ Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.²⁷

Order Nos. 202-25-11 and 202-25-11B were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."²⁸ The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."²⁹ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid

²³ *National Wildlife Federation, et al. (NWF) v. National Marine Fisheries Service, et al. (NMFS)*, case 3:01-cv-00640 (D. Or. Feb. 25, 2026) (order granting preliminary injunction).

²⁴ Fed. Def. Response to Minute Order at 4-5, *NWF v. NMFS, et al.*, case 3:01-cv-00640 (D. Or. Feb. 24, 2026).

²⁵ See, e.g., Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2582.

²⁶ See Dibble Decl. ¶ 28; ¶ 42, fig. 3.

²⁷ See, e.g., Dibble Decl. ¶ 26; Stevenson Decl. ¶ 18.

²⁸ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

²⁹ *Id.*

technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”³⁰

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³¹ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”³² This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Centralia Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

³⁰ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³¹ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³² Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through June 14, 2026.

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

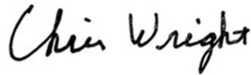
- A. From March 17, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)³³ or Southwest Power Pool Western RC³⁴ (in its role as the Reliability Coordinator). Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.
- B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.
- C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By March 31, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order. TransAlta shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

³³ See EIA-930A 2024 Data, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930A 2024 SCH 2, the BA Code for TransAlta Central Generation is GRID. See EIA-930 data reference tables, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930 data reference tables BA Code GRID is associated with Gridforce Energy Management, LLC.

³⁴ See Southwest Power Pool RTO and Western RC Footprint with Planned Expansion map, <https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png>.

- E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.
- G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.
- I. This Order shall be effective from March 17, 2026 through June 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 16th day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Washington Utilities and Transportation Commission
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl